RULE

Australian Energy Market Commission

DRAFT RULE DETERMINATION

NATIONAL ELECTRICITY AMENDMENT (MARKET MAKING ARRANGEMENTS IN THE NEM) RULE 2019

PROPONENT

ENGIE

27 JUNE 2019

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The Australian Energy Market Commission (AEMC or Commission) has decided not to make a draft rule in relation to a rule change request from ENGIE to require the Australian Energy Regulator (AER) to operate a tender for the provision of market making services in the National Electricity Market (NEM).

2 The Commission notes that the ASX has contracted with a number of industry participants to commence market making services in the NEM on 1 July 2019. The Retailer Reliability Obligation (RRO) and the associated Market Liquidity Obligation (MLO) can also be triggered from 1 July 2019. If the ASX participants meet the terms of their market making contracts then there would be no additional benefit in introducing alternative or additional market making schemes, although there would likely be higher costs.

3 For this reason the Commission considers the proposed rule would not, or would not likely, contribute to the National Electricity Objective (NEO). It has therefore decided not to make a draft rule.

4 In the course of analysing this rule change request, the Commission identified specific information gaps that affect the ability of:

- participants or potential entrants to observe electricity derivative (contract) prices
- regulatory agencies to assess the efficiency of the contract market and how it is working with the wholesale spot market.

5 The Commission will work with relevant market bodies and participants to address these gaps, including:

- to improve the transparency of the over-the-counter (OTC) market
- to enhance the AER's powers to monitor market liquidity, including the compliance of participants in the ASX market making scheme, and with reference to the structural characteristics of each jurisdiction.

6 The Commission invites submissions on this draft determination by 8 August 2019.

Background

7 On 25 October 2018, ENGIE submitted a rule change request to the Commission. The rule change request proposed changes to the National Electricity Rules (NER) that would require the AER to operate a tender for the provision of market making services in the NEM.

8 Market making services are designed to improve liquidity. In general, a liquid market is one in which a participant can reasonably expect to buy or sell a contract, within a reasonable price range, without that trade moving the price unreasonably. Market makers offer to buy or sell a volume of contracts within specified price ranges, so that participants have the opportunity to buy or sell contracts to manage their risks. For retailers and large consumers, financial (or hedge) contracts can deliver certainty in wholesale electricity costs for a particular period, to protect them from high or volatile spot market prices. For generators, hedge contracts can underwrite their revenues and thereby support operational commitment or investment

decisions.

9 Market making services can be voluntary, provided with incentives, or compulsory. There are many design options, but key elements commonly include, defined products, defined periods for market making, defined volumes and defined pricing.

10 In its Retail Electricity Pricing Inquiry (REPI) the Australian Competition and Consumer Commission (ACCC) recommended compulsory market making services be introduced in South Australia as a way to improve liquidity. The ACCC considered this would address concerns that South Australian retailers and large customers have had difficulty gaining contracts of the size, duration and price they would prefer. The Energy Security Board (ESB) was tasked with assessing that recommendation, but has postponed its assessment until this rule change is complete.

11 The rule change proponent does not agree that compulsory market making services in South Australia are suitable. It considers the structural conditions in South Australia mean that jurisdiction will have lower levels of liquidity, and it questions whether vertical integration is a significant factor contributing to lower liquidity. In response, the proponent has put forward its alternative market making proposal.

12 In addition to the ASX market making and the RRO/MLO schemes, there are four other mechanisms that may impact on market liquidity in the near term.

- The 2018 Prohibiting Energy Market Misconduct Bill included:
  - a prohibition on generators from withholding, or limiting their offers for, electricity contracts with the aim of substantially lessening competition in the market
  - a power for the Treasurer to direct participants to provide market making services.

  While the Bill was withdrawn prior to the Federal election, the government has subsequently indicated it will re-introduce the Bill.
- The South Australian government is progressing a derogation from the RRO rules, to provide the South Australian Energy Minister with increased discretion to trigger the RRO and MLO process in that state. This is expected to be operational from 1 July 2019.
- The commencement of the Default Market Offer (DMO) and Victorian Default Offer (VDO) on 1 July 2019 will likely have an effect on the contract market. Contracts help underwrite investment decisions (so investors prefer longer contracts), and they protect retailers against the risk of wholesale costs being higher than the retail prices they have offered to consumers via market or standing offer contracts. A DMO/VDO that sets a cap on retail pricing, and that is set just before a financial year, may undermine both of the main benefits of contracts by encouraging a shorter rather than a longer term approach to hedging.
- FEX Global (Financial and Energy Exchange Group) is planning to commence operating an electricity futures exchange in the second half of 2019. It is expected to offer the same suite of electricity products as the ASX at commencement.

13 The Commission published a consultation paper on the rule change on 20 December 2018. The paper outlined four broad approaches to market making and sought industry feedback

on the need for market making services and the merits of each of the approaches described. The four approaches were to:

- not make a rule, but monitor the effectiveness of the ASX and RRO/MLO schemes
- have a centralised tender process, as proposed in the rule change request
- have a trigger driven obligation
- have a compulsory market making requirement.

Summary of reasons

14 The Commission's draft determination not to make a draft rule is based on analysis that indicates market making arrangements additional to the ASX and RRO/MLO schemes are not likely to be efficient. On this basis, a rule to require additional market making services would not, or would not likely, contribute to the NEO.

15 Key findings include:

- Liquidity across the NEM is generally healthy. Liquidity in South Australia is much lower than in other regions. In particular, trading does not occur on a majority of days in South Australia whereas there are very few days without trading in other jurisdictions. It is not clear from the available data whether the lack of trades is because bids and offers are not posted, or because there are no buyers or sellers at the posted prices. Other metrics also indicate lower liquidity in South Australia.
  - For example, in 2017-2018 the churn ratio in South Australia was 1.0 compared to an average of 2.5 in other NEM jurisdictions, and South Australian bid-ask spreads averaged 6.7 per cent compared to 1.9-2.0 per cent in Victoria, Queensland and New South Wales.
- The structural characteristics of the South Australian market contribute to lower liquidity.
  - The available summer scheduled and semi-scheduled generation capacity of 4,408MW comprises 2,908MW of firm generation (87 per cent of which is gas generation) and 1,500MW of intermittent renewable generation. This means there are limited firm contracts offered, and because the firm contracts are predominantly from gas generators the prices tend to be higher than other NEM regions.
  - There is also a high level of vertical and horizontal integration which reduces the broader availability of contracts.
  - Demand is relatively low, comprising 12TWh of the 196TWh in the NEM. Given there is significant rooftop solar and a high proportion of wind generation, demand and supply can vary significantly in a short time.
  - There is limited interconnection to Victoria, which can assist supply if unconstrained.

  These factors contribute to high spot price volatility, which influences the willingness of participants to provide contracts and the pricing of those contracts. Understanding the influence of structural factors on liquidity is critical when considering market making arrangements. In markets where structural factors reduce liquidity to low levels, but market making requirements are high, there is potential for a market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of regulatory assessment.

- The ASX and RRO/MLO schemes are expected to improve liquidity compared to the levels currently observable in the market. These improvements should be most notable in South Australia. In particular the market making services specify requirements on market makers that are expected to improve the availability of prices, narrow the bid-ask spreads, and reduce the number of days without trades. Trading volumes are also expected to increase.
- The Commission engaged a consultant, NERA, to undertake an analysis of the incremental costs and benefits of additional market making requirements beyond the ASX and RRO/MLO schemes. The analysis modelled the four market making schemes described in the Consultation paper and referenced in paragraph 13. The analysis concluded that if the ASX scheme delivers to its design, then there would be no additional benefit from additional market making schemes. The other schemes are also likely to have higher costs.

16 It is for these reasons that the Commission's draft determination is not to make a draft rule.

Addressing information gaps in the market

17 In the process of assessing liquidity it became apparent that there are material information gaps in the contract market. The gaps undermine price discovery for participants, and the assessment of market conduct and performance by regulators.

18 Contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration). The visibility of these trades varies, with good visibility on the ASX, limited visibility of OTC trades, and no visibility of vertically integrated transactions. Traditional hedging products such as swaps and caps are generally visible on the ASX. Newer forms of contracting such as Power Purchase Agreements (PPAs), demand response contracts and weather derivatives are not traded on the ASX and have lower or no visibility.

OTC market transparency

19 The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format. The ESB has recently consulted with industry on this recommendation and has provided recommendations to the COAG Energy Council. It considered the preferable path is for the AEMC, AER and AFMA to work with market participants to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

20 The Commission has examined the AFMA survey and notes there are specific areas where improvement is required for it to adequately provide transparency of OTC trades. These include:

- **Price.** There is no price information in the AFMA survey. It is the main item that needs to be addressed in order to achieve transparency in the OTC market. The Commission understands this will also be the most contentious item for AFMA and its members to address.

- **Coverage.** This relates to the number of participants, and the products covered. There are product gaps in the survey; in particular, PPAs, demand response and weather derivatives. There were also only fourteen participants in the last AFMA survey, although they represented the majority of market generation and load, and the two main financial traders.
- **Timeliness.** The AFMA survey is conducted annually and released some months after the end of the financial year. This limits the usefulness of the data to industry. The Commission considers that at least monthly data would be necessary if the data was to be useful for price discovery.

21 The Commission agrees with the ESB that the effectiveness of an improved AFMA survey should be reviewed after a suitable period. However, it is important to agree some threshold issues in the near term. Such issues include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. These threshold decisions should be made before the end of 2019.

The AER's market monitoring function

22 The ACCC's REPI also recommended an expansion of the AER's market monitoring function to include the contract market, and enhancing the AER's information gathering powers. The ESB also examined this recommendation and supported the ACCC's position. It recommended that the AEMC and AER work to draft law changes required to give effect to the AER's expanded role. The recommended law changes are to be provided to the Energy Council.

23 The Commission has identified specific AER monitoring and reporting that it considers should be enabled by the proposed law changes, noting that the changes to give effect to the breadth of the ESB recommendation may be broader than these specific items. In particular:

- the AER will need to monitor the compliance of participants in market making schemes, as an input into assessing the effectiveness of market making schemes in delivering liquidity. If low liquidity is observed in a market in which market making services are provided, it will be important to understand whether the low liquidity is caused by participants' non-compliance or the scheme design. The absence of clear compliance data would cloud analysis of whether market making schemes are sufficient and efficient in delivering liquidity. From 1 July 2019, the AER will have powers to monitor compliance with the MLO. Similar powers will be required for the ASX market making scheme.
- in monitoring and reporting on market liquidity, the AER should take account of:
    - the levels of compliance achieved in the ASX market making scheme and the MLO if triggered.
    - the liquidity factors examined in this rule change process, at least including the availability of prices, the bid-ask spreads, the number of days with trading, and trading volumes
    - the structural characteristics of each jurisdiction.

24 The Commission will also work with the AER to determine whether large vertically integrated market participants should regularly report specific additional data to enable ongoing assessment of market conduct and performance. In the course of this rule change, the Commission has not attempted to examine the potential range of information that may be required to monitor and report on the contract market, but it has identified two specific areas for further consideration. These are:

- Information on internal pricing and contractual conditions compared to external pricing and conditions for contracts to third party retailers or third party generators. This data would inform questions of fair dealing or equivalence between a vertically integrated participant's internal and external contracting.
- Information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management. This data would inform questions about withholding in the contract market.

25 These issues are commonly raised but there is poor data availability to enable assessment. The Commission will examine these issues more closely in conjunction with the AER as part of developing the required law changes to enhance the AER's market monitoring role.

The interaction of the contract and wholesale spot markets

26 As context for this rule change it is important to understand the interaction of the contract and wholesale spot markets.

27 The National Electricity Market (NEM) is an energy only market, where all generation is provided into a central pool, and all energy is purchased from the pool. AEMO operates the market by balancing supply and demand, and determining the price for the supply of wholesale electricity, every five minutes. The wholesale spot price is calculated every 30 minutes, and is the price that is paid by purchases for their consumption and to generators for their output. The spot price is the average of the six dispatch intervals that make up the 30 minute spot price period. A spot price is determined separately at a regional reference node within each region.

28 Spot market prices vary with changing demand and supply conditions, resulting in significant wholesale price variation in different regions, at different times of day, and different times of year. Spot market prices can range from the market price cap of $14,500/MWh to the market floor price of -$1,000/MWh.[1]

29 The volatility of wholesale spot prices creates uncertainties for buyers and sellers in the market. The uncertainty relates to the expected cash flows of participants from buying or selling electricity. For example:

- a retailer needs to buy wholesale electricity in order to provide it to consumers. It will commonly contract with consumers to provide electricity at prices that are fixed for a given period, but will face uncertain and varying wholesale spot prices over that supply period.

1 The market price cap will increase to $14,700/MWh on 1 July 2019

- a generator needs to cover its operational (e.g. fuel) and investment (i.e. return of, and return on, capital) costs over time, but faces an uncertain and varying revenue stream.

30 Both participants face risk to their cash flows. In order to manage these risks, participants can enter into financial contracts. For example, the above retailer and generator can enter into a contract with an agreed price for the supply of an agreed quantity of electricity for a given period. In this way, the retailer gains certainty over its costs and the generator over its revenue.

31 The contract market:

- supports retail competition and market entry. It allows participants to test their business models in the market with some certainty over a significant component of their costs
- enables generators to commit to generating in particular periods and (at least) cover their short term costs
- helps underwrite investment, by de-risking investment in long-lived assets
- provides incentives for generators to maintain system reserves.[2]

32 Participants can also manage their risk physically, via vertical or horizontal integration.

Linking financial incentives to the system's physical needs: example

33 Assume a generator sells a swap contract to a retailer that limits the price the retailer pays to $60 per MWh. This means that irrespective of the spot price, the generator will receive $60 per MWh from the retailer (for the quantity of electricity agreed in the contract) provided it is generating the quantity of the energy covered by the contract during the periods of time that the contract is in force.

34 During high price events where system reliability is stressed, for example during heat-waves, the penalty for not being reliable is extreme.

35 For example, during a market price cap event, when the spot price is at its maximum $14,500, a generator that is contracted at $60 per MWh will lose $14,440 per MW per hour that it is not available. For a 500MW unit, this equates to a loss of $7.2 million an hour.

36 However, this link with the physical market only applies to financial derivative contracts (most commonly 'swaps' and 'caps') that are linked to spot prices, not Power Purchase Agreements.

2 For example a generator with four turbines may use two to supply its own retail load, offer contracts for the output of the third, while holding the fourth in reserve to account for an unexpected outage. In this way, it protects its contract position and provides system reserves capacity. Another generator may commit a higher proportion of its output to self-supply or contracting, depending on its business model and risk tolerance.

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1 BACKGROUND

This chapter describes the policy and legislative context within which this rule change process is being conducted, and notes the risk of higher costs if multiple market making obligations operate concurrently.

1.1 The context within which this rule change is being assessed

There are a number of different market making schemes or proposals that are being progressed or considered at the same time as this rule change. Other market and regulatory developments that may impact on market making services are also described in this section.

1.1.1 Retailer Reliability Obligation

At the 26 October COAG Energy Council meeting, Ministers agreed that the ESB would progress development of amendments to the NEL that would give effect to the RRO. The RRO was a revised version of the National Energy Guarantee (NEG), in that it progressed the reliability but not the emission reduction requirements that were part of the original NEG design.

A consultation paper was published on 8 November 2018. To accompany the consultation paper, the ESB also released draft amendments to the National Electricity Rules (NER) and an illustrative timeline. On 8 March 2019, the ESB published the Retailer Reliability Obligation Draft Rules Consultation Paper and the final rules package to implement the RRO was approved by the COAG Energy Council on 4 June 2019. The RRO is scheduled to commence on 1 July 2019.

The South Australian government is also progressing derogation from the RRO rules, to provide the South Australian Energy Minister increased discretion to trigger the RRO and MLO process in that state. This is also expected to be operational from 1 July 2019.

Although the prime focus of the RRO is to facilitate reliability, the associated MLO is a market making requirement, and therefore an important contextual factor in the assessment of this rule change.

1.1.2 ASX market making incentive scheme

In July 2018 the ASX commenced a process to introduce voluntary market making services in the electricity futures market.[3] A number of physical participants have supported the scheme, and are understood to have signed market making agreements with the ASX. In return for providing market making services, participants receive discounted exchange fees and a share of profit from the increased value of trade driven by market making. Participants may also have been motivated to participate in the scheme in order to avoid further regulatory action, including compulsory obligations for market making.

3 Expressions of interest for Australian Electricity Market Making, https://www.asxenergy.com.au/newsroom/industry_news/market-making-expression-of-

The terms of the market making arrangement have been developed in parallel with those of the MLO, and are largely the same. A comparison of the key features and requirements of the two schemes is available in appendix e in this draft determination.

The scheme is due to commence on 1 July 2019.

1.1.3 ACCC REPI recommendation 7 and ESB advice

The ACCC reviewed the contract market in the REPI.[4]It found that in certain regions of the NEM, particularly South Australia, the level of market liquidity and the advantages afforded by vertical integration mean that it is difficult for new entrants or smaller retailers to compete effectively in the market.

The ESB was asked to provide advice on the ACCC recommendation, and on 28 September 2018 published a consultation paper on Market Making Requirements in the NEM. The paper sought industry submissions on a proposal to create a MLO that combined the reliability requirement under the NEG with the liquidity requirement under the ACCC's REPI recommendation 7.[5]

The ESB has deferred further work on this recommendation until after this rule change process is complete.

1.1.4 Commonwealth legislation

In 2018 the Treasurer introduced the *Prohibiting Energy Market Misconduct Bill* to Parliament. The legislation was referred to a Senate Committee before being withdrawn prior to the federal election. Since being re-elected, the government has indicated it will re-introduce the Bill.[6]

The Bill set out three kinds of prohibited conduct in relation to:

- retail prices
- the electricity financial contract market
- the wholesale electricity market.

Under the proposed Bill the ACCC may recommend that the Treasurer make an order that would require an electricity company to offer electricity financial contracts to third parties. This can be done if the ACCC reasonably believes that a person has engaged in prohibited conduct in relation to the electricity contract market or wholesale electricity market. It is intended that the making of a contracting order by the Treasurer would only occur in respect of more serious contraventions.

4 ACCC Retail Electricity Pricing inquiry Final Report, https://www.accc.gov.au/publications/restoring-electricity-affordabilityaustralias-competitive-advantage

5 ESB consultation paper: Market Making Requirements in the NEM, September 2018, http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Market%20Making%20Requirements%20in%20the%20NEM%20Consultation%20Paper.pdf

6 see The Australian, 29 May 2019.

1.1.5 Competition in exchange services

FEX Global (Financial and Energy Exchange Group) is planning to commence operating an electricity futures exchange in the second half of 2019. It has advised it will offer the same suite of electricity products as the ASX at commencement.

Competition in exchange services has the potential to improve contract market liquidity. Product offerings and fee structures may diverge over time, potentially providing a broader suite of products and options to participants.

1.1.6 The Default market offer and Victorian default offer

The commencement of the Default Market Offer (DMO) and Victorian Default Offer (VDO) on 1 July 2019 will likely have an effect on the contract market.

Contracts help underwrite investment decisions, so investors prefer longer contracts that are more aligned to the life of the assets they are investing in. Contracts also protect retailers against the risk of wholesale costs being higher than the retail prices they have offered to consumers via market or standing offer contracts.

Given the DMO and VDO set caps on the level of retail pricing that is allowed, and those prices are scheduled to be set just before each financial year, the process may encourage a shorter rather than longer term approach to hedging. For example, retailers will be less likely to commit to wholesale contracts until they know what prices they are allowed to charge consumers. This may undermine generator attempts to sell longer term supply contracts.

1.2 Risks of layered market making obligations

The Commission notes that with multiple processes potentially allowing for the introduction of market making, there is a risk that separately layered arrangements may increase the overall costs of market making.

At present there is an industry led process to work with the ASX in addition to the RRO/MLO scheme. While it may be assumed that there will be a reasonable coincidence of the market makers under each scheme, this is not assured given the different mechanisms used to identify the market makers.

If an incentivised scheme was operating alongside the RRO/MLO, there is a strong probability that the coincidence of market makers would fail. This is because financial participants would likely participate in an incentivised scheme, whereas the RRO/MLO is restricted to physical market operators.

In practice this could result in incentivised participants receiving the incentive payment for market making, and then seeking additional payment from participants captured by the RRO/MLO scheme to meet the MLO on their behalf. Any additional payment would represent an increase in the social cost of market making.

2 THE RULE CHANGE REQUEST

On 25 October 2018, ENGIE proposed a rule change to require the AER to operate a tender for the provision of market making services in the NEM. The proponent stated this is the most appropriate method for identifying parties who have the sophistication and appetite to take on the risks associated with market making.

The rule was proposed as a preferable alternative to the compulsory market making proposals that were outlined in the ACCC REPI report and the ESB consultation paper on *Market Making Requirements in the NEM*.[7]

Copies of the rule change request may be found on the AEMC website, www.aemc.gov.au.

2.1 Rationale for the rule change request

The proponent lodged the rule change request:

- to enable more detailed consideration of the appropriateness of a mandatory market making mechanism
- to propose an alternative approach that seeks to manage the issues with a compulsory obligation that it claims were identified (but not addressed) in the ACCC's REPI and in the ESB's consultation paper on Market Making Requirements in the NEM.

The proponent argued that several fundamental questions around the justification for market making obligations, either in South Australia or more broadly, have not been adequately addressed. In particular, it noted concerns with the diagnosis of liquidity and market failure, and raised concerns about a compulsory market making requirement.

2.1.1 Issues with the diagnosis of the problem and market failure

The proponent suggested that some generators and hedge providers may have difficulty finding buyers for contracts on the terms they desire. It did this while accepting that some retailers may have difficulty obtaining contracts of the size, duration or price they would prefer. Neither of these factors, in the view of the proponent, is necessarily grounds for concluding there has been market failure.

The proponent suggested that the case has not been sufficiently made that vertical integration is the primary (or even a significant) contributor to the problems faced by both sides of the market in South Australia. The proponent does not feel that the South Australian market conditions have been effectively diagnosed, particularly compared to other states. It also does not consider that an adequate link has been demonstrated to conclude market making as proposed by the ACCC and ESB will solve those problems.

The proponent considers the structural characteristics of the South Australian market need to be analysed to understand the hedging market. It is a small market with a high penetration of renewable generation, reliant on gas generation to provide firm capacity and with important interconnection with the Victorian market. The proponent rejects the suggestion

7 ESB consultation paper: *Market Making Requirements in the NEM*, September 2018.

that vertical integration has led to the withholding of hedge products from competing retailers. It claims there is no evidence of such behaviour, particularly in an environment of rising prices. It also pointed out that the ACCC REPI acknowledged the prices for trades of bigger and smaller participants in South Australia were largely the same.

The importance of gas generation to electricity generation in South Australia was also noted. The proponent maintained that the lack of gas market liquidity in terms of the ability to enter and exit positions, the size of contracts, the tenure of contracts and the lack of standardisation of contracts has a direct bearing on the liquidity of electricity contracts. It was stated that a gas generator should not be expected to provide the same level of liquidity as a coal-fired generator. ENGIE considered this issue was not adequately addressed in either the ACCC REPI or in the ESB consultation paper on market making requirements in the NEM.

The experience of firm generators in South Australia, according to the proponent, contrasts with the conclusions of the ACCC REPI, in that it highlights the difficulty some firm generators have had in securing contracts. Significant effort was made by the last coal-fired generator (Northern) to sell contracts but the absence of parties willing to buy contracts contributed to its closure. This was also the case prior to a unit of Pelican Point being withdrawn from the market in 2015 (the unit subsequently returned in 2017). The proponent noted that one of the key drivers of the NEG was to encourage large customers to contract to avoid the retirement of firm generators. The proponent suggested the theory has now been turned on its head, with arguments of contract withholding by vertically integrated retailers taken as justification for market making.

The rule change request pointed out that during the current deliberations on the future of the UK scheme, Ofgem has acknowledged the findings by the Competition and Markets Authority that they "have not identified any areas in which vertical integration is likely to have a detrimental impact on competition for independent suppliers and generators".[8]

The rule change request suggested a more detailed analysis of these issues is required in South Australia and more broadly across the NEM.

2.1.2 Issues with a compulsory obligation

The proponent identified a number of issues with a compulsory market making obligation. Introducing a requirement that will force specific market participants with physical generation to buy and sell contracts that they would be unwilling to trade freely, due to a lack of financial incentives and an unwillingness to take on additional risk is, in the view of the proponent, a significant change in the operation of the NEM.

Where contractual terms may be unfavourable for either party, it is not appropriate for one party to be obliged to accept those terms or conditions. Requiring a party to take on additional risk or offer hedges below cost will undermine asset viability and work to destabilise the market, in South Australia and more broadly. A compulsory obligation fails to examine the impacts on disadvantaged parties and to appreciate the long term effects on the market.

8 Rule change request p.5.

The proponent identified a number of problems with a compulsory obligation:

- the overall risk capacity in the market is unlikely to increase, with participants having to adjust their risk position for additional hedges they are required to offer
- obliging some participants to trade with lower credit quality parties will likely increase costs for consumers
- an obligation may not benefit the small retailers it is intended to help if trade sizes are not small enough. Standard futures contracts are also relatively blunt instruments for a small retailer without scale. Smaller retailers, according to the proponent, tend to set up more tailored arrangements that match the needs of their portfolio. The larger participants who provide these products will have to adjust their risk exposure to allow for an obligation
- physical players have operating and financial risk constraints. An obligation will not increase their overall capacity to manage risk
- the proponent suggests an obligation to provide hedges outside an integrated portfolio may actually reduce the level of contracts available in the market given integrated participants have more of a natural hedge when they trade with themselves and so may be willing to offer more capacity when trading on this basis
- operating constraints such as generator outages and fuel supply constraints, for example a lack of liquidity in gas contracts, may constrain a generator below the full extent of their capacity
- it is not appropriate for obligated parties to take on unnecessary costs. Obligated parties may find it difficult to move prices during periods of high volatility, thereby resulting in significant and unexpected costs. A market making obligation may also involve significant IT costs
- current Australian Financial Services Licence arrangements prohibit participants in a market from being a market maker unless they are licensed to do so
- a compulsory obligation may undermine the business case for the voluntary market making incentive scheme being developed by the ASX.

2.2 Proposed solution

2.2.1 Proposed rule

The rule change request proposed that a tender be run by the AER for voluntary market making services in the National Electricity Market (NEM).[9] The proponent maintained that this is the most appropriate method for identifying parties who have the sophistication and appetite to take on the risk associated with a market making service. The proponent suggested the tender should:

- be conducted every three to five years
- cover all regions in the National Energy Market (NEM)

9 Rule change request p.8.

- allow the market making arrangement to remain in place on an ongoing basis with no trigger mechanism
- specify parcel sizes, required cumulative exposure, required spreads and periods of offer for each region that will remain in place for the full duration of the tender period
- be open to financial or other providers
- permit the successful tenderer to sub-contract directly with physical and financial market participants in order to provide the market making service
- require the successful tenderer to manage the risk of default in participants' market making positions
- provide flexibility in relation to both ASX and OTC products
- recover the costs of the tender from customers
- prescribe penalties for non-performance
- specify the market monitoring required, noting that this may depend on the type of product used to meet the obligation
- be reviewed by the AEMC in advance of each re-tender.

The tender would be independent of the NEG reliability obligation[10], and therefore any market making obligations proposed by the NEG should be considered unwarranted.

The rule change proposal also refers to the ASX Market Making Incentive Scheme and suggests complementing this scheme based on voluntary participation is an important consideration.

2.2.2 Contribution to the NEO

The proponent stated that proposals to require compulsory market making arrangements have not examined the impacts on disadvantaged parties (such as the increased risk of loss given default) or the long-term effects (such as a disincentive to invest or potential early asset retirements) the arrangement may have. A tender for voluntary market making services would not create these additional risks for existing market participants and would provide a new service in the market with parties willing to take on the additional risk for a price.

The proponent concluded the proposed rule change is in the long term interests of customers and promotes a number of beneficial outcomes consistent with the NEO that would not be provided by a compulsory market making arrangement.

2.2.3 Benefits described by the proponent

The proponent considers there would be a range of benefits if the proposed market making scheme is implemented.

- *An economically efficient allocation of risk in the NEM* — the allocation of risk would be managed by sophisticated financial intermediaries that are effective at handling and

10 This is now the Retailer Reliability Obligation

pricing financial risk. This would facilitate the management of new entrant retailers without placing unmanageable risks on selected physical participants.

- *Commercial drivers not distorted* — the commercial drivers underpinning participants' hedge positions would not be distorted.
- *Transparency and cost recovery* services provided outside of the physical market would be provided transparently and with appropriate cost recovery.
- *Investor confidence in the market*— shareholder and investor expectations would not be under-mined by compulsory market making obligations. This would avoid placing additional risk premiums on investment in some or all regions of the NEM to account for unmanageable risks and unrecoverable costs.
- *Encourages participation of specialist providers* — the proposed rule may encourage the entrance of specialist providers who may be better placed to provide market making services.
- *Contracting consistent with capability* — it should minimise the potential for entities to provide risk management services beyond their capability to do so, or to provide hedges beyond the financial capability of the underlying generation asset.
- *Obligatory mechanism unwarranted* — the proposal minimises the need for market intervention as proposed under the NEG.
- *Certainty provided by an ongoing mechanism* — an ongoing mechanism, with firm terms set for each three to five year period, removes the uncertainty that would be created by a trigger mechanism.
- *Greater confidence in the NEM and related markets* — a voluntary market making arrangement will promote confidence in the NEM and closely related markets, for example gas and large generation certificates (LGCs).

2.2.4 Costs described by the proponent

The costs of the tender and the costs of participants taking part in the tender and meeting those obligations over a three to five year timeframe are not set out in the rule change proposal. However, the proposal suggests that the costs of the tender be "recovered from customers".[11]

2.3 Rule change initiation and submissions received

On 20 December 2018, the Commission commenced the rule making process and published a consultation paper on the issues raised by the proponent.[12]

Submissions to the consultation paper closed on 7 February 2019. Fourteen submissions were received. All issues raised by stakeholders have been considered and responded to in this draft rule determination with an overall summary provided in section 2.3.2 below.

11 ENGIE rule change request, p.9

12 The notice of commencement was published under s.95 of the National Electricity Law (NEL).

2.3.1 Market making scheme options

In order to assess the issues associated with the rule change proposal, the AEMC put forward four broad market making options for consideration in the consultation paper. These options were to:

- not make a rule, but monitor the effectiveness of the ASX and RRO/MLO schemes
- have a centralised tender process, as proposed in the rule change request
- have a trigger driven obligation
- have a compulsory market making requirement.

2.3.2 Summary of submissions to the consultation paper

Respondents to the consultation paper broadly fall into two groups:

1. Larger and medium-sized retailers consider liquidity in the contract market is sufficient for retailers to access the risk management tools needed to compete in the retail market. Where liquidity is seen to be a problem, this is largely confined to the South Australia market and is a consequence of the particular characteristics of that market. Market making in so far as it does not address these market issues, is unlikely to resolve issues of contract market liquidity. This group supports the voluntary ASX scheme as the solution to implementing market making in the NEM and for the most part is opposed to compulsory market making as the solution to any issues seen with liquidity in the contract market.
2. ERM Power, the ACCC and the EUAA do consider there is a problem with the lack of liquidity in the South Australian contract market in particular, and support some form of compulsory market making.

The solution put forward by the proponent is generally favoured by participants that prefer voluntary and incentivised solutions to market making, as opposed to a compulsory obligation. Few participants are in favour of a tender in its own right however. Some respondents, such as Meridian, oppose the introduction of a tender, on the grounds that a trading exchange such as the ASX is best placed to run a market making scheme, rather than the AER. The AER is also opposed to the introduction of a tender for market making, on the grounds that the operation of the tender would be onerous to implement and operate.

2.4 Consultation on draft rule determination

The Commission invites submissions on this draft rule determination by 8 August 2019.

Any person or body may request that the Commission hold a hearing in relation to the draft rule determination. Any request for a hearing must be made in writing and must be received by the Commission no later than 4 July 2019.

Submissions and requests for a hearing should quote project number ERC0249 and may be lodged online at www.aemc.gov.au.

3 DRAFT RULE DETERMINATION

3.1 The Commission's draft rule determination

The Commission's draft rule determination is to not make the proposed rule.

The Commission's reasons for making this decision are set out in section 3.5 (and in more detail in the relevant chapters and appendices).

This chapter outlines:

- the rule making test for changes to the National Electricity Rules (NER)
- the assessment framework for considering the rule change request
- potential legal issues with making a rule
- a summary of reasons for not making a draft rule.

Further information on the legal requirements for making this draft rule determination is set out in Appendix B.

3.2 Rule making test — achieving the NEO

Under the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the national electricity objective (NEO).[13] This is the decision-making framework that the Commission must apply.

The NEO is:[14]

> to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The Commission has identified that the relevant aspects of the NEO are the efficient investment in, and efficient operation and use of, electricity services with respect to the price and reliability of supply of electricity.

3.3 Assessment framework

In assessing the rule change request against the NEO the Commission has considered the following principles:

- **Enhance transparency and predictability**: The transparency of information is a key feature of the efficient operation of the NEM. Market participants need access to clear, timely and accurate information in order to allow them to make efficient commercial and operational decisions. The Commission has considered the degree to which a market making service could make market participants more confident in contract prices.

13 Section 88 of the NEL.

14 Section 7 of the NEL.

- **Enhance wholesale and retail market competition**: The greater ability to trade in electricity futures contracts at prices that are visible to all market participants helps to lower barriers to entry and competition both in the wholesale and retail market. TheCommission has considered the degree to which this will help to improve price outcomes for consumers.
- **Efficiency of investment in and retirement of generation capacity and demand response:** Improving the provision of information, transparency and predictability of information in the NEM can assist in promoting efficiency of investment in, and operation of, generation capacity and demand response decisions. By improving the provision of information, this can potentially help energy market participants to make more efficient decisions.
- **Administrative costs**: Market making arrangements could impose new costs on both participants and the party or parties administering the arrangements.

3.4 Potential legal issues with making a rule

As part of assessing the rule change request, the Commission has considered what (if any) legal issues may arise in relation to making a Rule to introduce a market making mechanism. While the Commission has determined not to make a draft rule, the following legal matters were identified when assessing the rule change request:

- **Rule-making power** – The Commission considers that a market making mechanism would likely fall within the scope of the Commission's rule-making power under section 34(1)(a)(iii) of the National Electricity Law.[15] However, the Commission is unlikely to have sufficient rule-making power to introduce a market making mechanism that regulates financial intermediaries (that is, the mechanism would need to be limited to parties that participate in the wholesale exchange).
- **Conferral of functions on the AER** – If the market making mechanism involved the AER running a tender process for market making in the NEM (or otherwise involved the AER administering some aspect of the mechanism), it is likely that such a role would constitute conferring a function or power on the AER under the Rules. While the Commission can confer additional function or powers on the AER under the Rules, the conferral of any new function or power also requires the unanimous agreement of the COAG Energy Council.[16] Also, depending on the exact form of the mechanism, there may be limitations on the AER's ability to hold funds under the mechanism (e.g. if it involved incentive payments being made to market makers) or enter into contracts with market makers.

15 Section 34(1)(a)(iii) of the NEL provides that the Commission may make rules "for or with respect to… regulating… the activities of persons (including Registered participants) participating in the national electricity market or involved in the operation of the national electricity system… ".

16 AER (as a Commonwealth body) may only perform functions conferred by a State law (e.g. the National Electricity Law) if a Commonwealth law authorises the AER to perform those functions. The *Competition and Consumer Act 2010* (Cth) ("CCA") authorises the conferral of functions on the AER under State law if (and only if) the conferral is "in accordance with the Australian Energy Market Agreement…" (s. 44AI of the CCA). Certain functions are granted to AER under clause 9 of the Australian Energy Market Agreement (AEMA), which include functions related to economic regulation, regulation of Retail Energy Markets and "*such other functions as may from time to time be agreed unanimously by the MCE Ministers representing the Parties that have elected to be subject to the jurisdiction of the AER and are conferred by legislation*".

- **Australian financial services license ('AFSL')** – A party making offers to buy or sell derivatives under a market making mechanism will likely need to hold an AFSL. The form of any rule introducing a mandatory market making mechanism would need to take into account a party's ability to hold the requisite licence to perform its obligations under the mechanism.

The above reflect threshold legal issues with introducing a market making mechanism. Additional legal matters would likely need to be considered depending on the exact form of the mechanism.

3.5 Summary of reasons

The Commission's draft determination not to make a draft rule is based on analysis which indicates that market making arrangements additional to the ASX and RRO/MLO schemes are not likely to be efficient. On this basis, a rule to require additional market making services would not, or would not likely, contribute to the NEO.

Key findings include:

- Liquidity across the NEM is generally healthy. Liquidity in South Australia is much lower than in other regions. In particular, trading does not occur on a majority of days in South Australia whereas there are very few days without trading in other jurisdictions. It is not clear from the available data whether the lack of trades is because bids and offers are not posted, or because there are no buyers or sellers at the posted prices. Other metrics also indicate lower liquidity in South Australia.
  - For example, in FY18 the churn ratio in South Australia was 1.0 compared to an average of 2.5 in other NEM jurisdictions, and South Australian bid-ask spreads averaged 6.7 per cent compared to 1.9-2.0 per cent in Victoria, Queensland and New South Wales.

  Liquidity is examined in Chapter 4.
- The structural characteristics of the South Australian market contribute to lower liquidity. These include:
  - The generation capacity of 4,408MW comprises 2,908MW of firm generation (87 per cent of which is gas generation) and 1,500MW of intermittent renewable generation. This means there are limited firm contracts offered, and because the firm contracts are predominantly from gas generators the prices tend to be higher than other NEM regions.
  - There is also a high level of vertical and horizontal integration which reduces the broader availability of contracts.
  - Demand is relatively low, comprising 12TWh of the 196TWh in the NEM. Given there is significant rooftop solar and a high proportion of wind generation, demand and supply can vary significantly in a short time.
  - There is limited interconnection to Victoria which can assist supply if unconstrained.

  These factors contribute to high spot price volatility, which influences the willingness of participants to provide contracts and the pricing of those contracts. Understanding the influence of structural factors on liquidity is critical when considering market making arrangements. In markets where structural factors reduce liquidity to low levels, but market making requirements are high, there is potential for a market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of regulatory assessment.

The structural factors that affect liquidity in South Australia are examined in detail in Chapter 5.

- The ASX and RRO/MLO schemes are expected to improve liquidity compared to the levels currently observable in the market. These improvements should be most notable in South Australia. In particular the market making services specify requirements on market makers that are expected to improve the availability of prices, narrow the bid-ask spreads, and reduce the number of days without trades. Trading volumes are also expected to increase.
- The Commission engaged a consultant, NERA, to undertake an analysis of the incremental costs and benefits of additional market making requirements beyond the ASX and RRO/MLO schemes. The analysis modelled the four market making schemes described in the Consultation paper and in section 2.3.1. The conclusions of the analysis were that if the ASX scheme delivers to its design, then there would be no additional benefit from additional market making schemes. The other schemes are also likely to have higher costs.

  The NERA report is summarised briefly in Chapter 6 and is available on the AEMC's website.

It is for these reasons that the Commission's draft determination is not to make a draft rule.

3.5.1 Addressing information gaps in the market

In the process of assessing liquidity it became apparent that there are material information gaps in the contract market. The gaps undermine price discovery for participants, and the assessment of market conduct and performance by regulators.

Contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration). The visibility of these trades varies, with good visibility on the ASX, limited visibility of OTC trades, and no visibility of vertically integrated transactions. Traditional hedging products such as swaps and caps are generally visible on the ASX. Newer forms of contracting such as Power Purchase Agreements (PPAs), demand response contracts and weather derivatives are not traded on the ASX and have lower or no visibility.

OTC market transparency

The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format. The ESB has recently consulted with industry on this recommendation and has provided recommendations to the COAG Energy Council. It considered the preferable path is for the AEMC, AER and AFMA to work with market participants to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

The Commission has examined the AFMA survey and notes there are specific areas where improvement is required for it to adequately provide transparency of OTC trades. These include:

- **Price.** There is no price information in the AFMA survey. It is the main item that needs to be addressed in order to achieve transparency in the OTC market. The Commission understands this will also be the most contentious item for AFMA and its members to address.
- **Coverage.** This relates to the number of participants, and the products covered. There are product gaps in the survey; in particular, PPAs, demand response and weather derivatives. There were also only fourteen participants in the last AFMA survey, although they represented the majority of market generation and load, and the two main financial traders.
- **Timeliness.** The AFMA survey is conducted annually and released some months after the end of the financial year. This limits the usefulness of the data to industry. The Commission considers that at least monthly data would be necessary if the data was to be useful for price discovery.

The Commission agrees with the ESB that the effectiveness of an improved AFMA survey should be reviewed after a suitable period. However, it is important to agree some threshold issues in the near term. Such issues include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. These threshold decisions should be made before the end of 2019.

The AER's market monitoring function

The ACCC's REPI also recommended an expansion of the AER's market monitoring function to include the contract market, and enhancing the AER's information gathering powers. The ESB also examined this recommendation and supported the ACCC's position. It recommended that the AEMC and AER work to draft law changes required to give effect to the AER's expanded role. The recommended law changes are to be provided to the Energy Council.

The Commission has identified specific AER monitoring and reporting that it considers should be enabled by the proposed law changes, noting that the changes to give effect to the breadth of the ESB recommendation may be broader than these specific items. In particular:

- the AER will need to monitor the compliance of participants in market making schemes, as an input into assessing the effectiveness of market making schemes in delivering liquidity. If low liquidity is observed in a market in which market making services are provided, it will be important to understand whether the low liquidity is caused by participants' non-compliance or the scheme design. The absence of clear compliance data would cloud analysis of whether market making schemes are sufficient and efficient in delivering liquidity. From 1 July 2019, the AER will have powers to monitor compliance with the MLO. Similar powers will be required for the ASX market making scheme.
- in monitoring and reporting on market liquidity, the AER should take account of:

- the levels of compliance achieved in the ASX market making scheme and the MLO if triggered.
- the liquidity factors examined in this rule change process, at least including the availability of prices, the bid-ask spreads, the number of days with trading, and trading volumes
- the structural characteristics of each jurisdiction.

The Commission will also work with the AER to determine whether large vertically integrated market participants should regularly report specific additional data to enable ongoing assessment of market conduct and performance. In the course of this rule change, the Commission has not attempted to examine the potential range of information that may be required to monitor and report on the contract market, but it has identified two specific areas for further consideration. These are:

- Information on internal pricing and contractual conditions compared to external pricing and conditions for contracts to third party retailers or third party generators. This data would inform questions of fair dealing or equivalence between a vertically integrated participant's internal and external contracting.
- Information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management. This data would inform questions about withholding in the contract market.

These issues are commonly raised but there is poor data availability to enable assessment. The Commission will examine these issues more closely in conjunction with the AER as part of developing the required law changes to enhance the AER's market monitoring role.

4 ASSESSING LIQUIDITY IN THE CONTRACT MARKET

This chapter:

- defines liquidity
- assesses liquidity in NEM jurisdictions
- describes alternative risk management options that are currently not captured in the available liquidity metrics.

4.1 Defining liquidity

Liquidity is a broadly used term, but there is not a standardised definition. In general, a liquid market is one in which a participant can reasonably expect to trade, within reasonable bid-ask spreads, without that trade moving the price unreasonably. Put another way, liquidity is a measurement of the ease with which, in the absence of new information altering an asset's fundamental price, large volumes of the asset can be bought or sold quickly at a reasonable price. In practice, the broad definition of liquidity means assessments should be referenced against a range of indicators. Reliance on individual indicators risks misunderstanding the level of liquidity in a market.

Liquidity should also be observed over time, in particular to assess whether increases or declines in liquidity in one market are offset by increases or decreases elsewhere. For example whether declining liquidity on the ASX is offset by increasing liquidity in OTC trading or the demand response register. See Figure 7.2 in chapter 7 to see this impact in South Australia.

The metrics described below provide a useful indication of liquidity in different NEM jurisdictions, but it is noted that the data available to the Commission is incomplete and additional insights may be available from a richer data set. Notably, the detailed data the ACCC collected from participants via its information gathering powers as part of the REPI was not available to the Commission.[17] The metrics used to assess liquidity in the draft determination are:

- The number of days in which trading occurred — this provides an indication of the ease with which participants have been able to buy or sell contracts. Notably, it is not clear whether prices were posted on non-trading days and no transactions occurred, or whether no prices were posted and there was no opportunity to trade. Participant decisions to trade are also dependent on contract prices being acceptable.
- The average number of transactions each day — this provides another indication of the level of contract trading activity.
- Contract turnover and churn — these metrics demonstrate actual volumes traded, and volume traded as a proportion of total demand in each region. High churn ratios indicate the physical demand for electricity has been traded many times over, and give traders confidence that prices reflect current market conditions and expectations. Conversely, low

17 The ACCC stated legal reasons prevented it from sharing data with the AEMC.

churn ratios may indicate 'stale' prices and reflect a lack of confidence from traders that the price reasonably reflects market conditions.

- Bid-ask spreads — this is the difference between a seller's asking price and a buyer's bid price for a contract. The spread represents the cost of trading in and out of positions in the market (transaction costs). It is a useful metric in that it captures both explicit transaction costs, which relate to expenses such as order processing costs and taxes associated with trades, and implicit transaction (execution) costs. In general, higher transaction costs reduce the demand for trades and encourage traders to seek OTC or physical alternatives (such as vertical integration) to hedge their spot price risks.

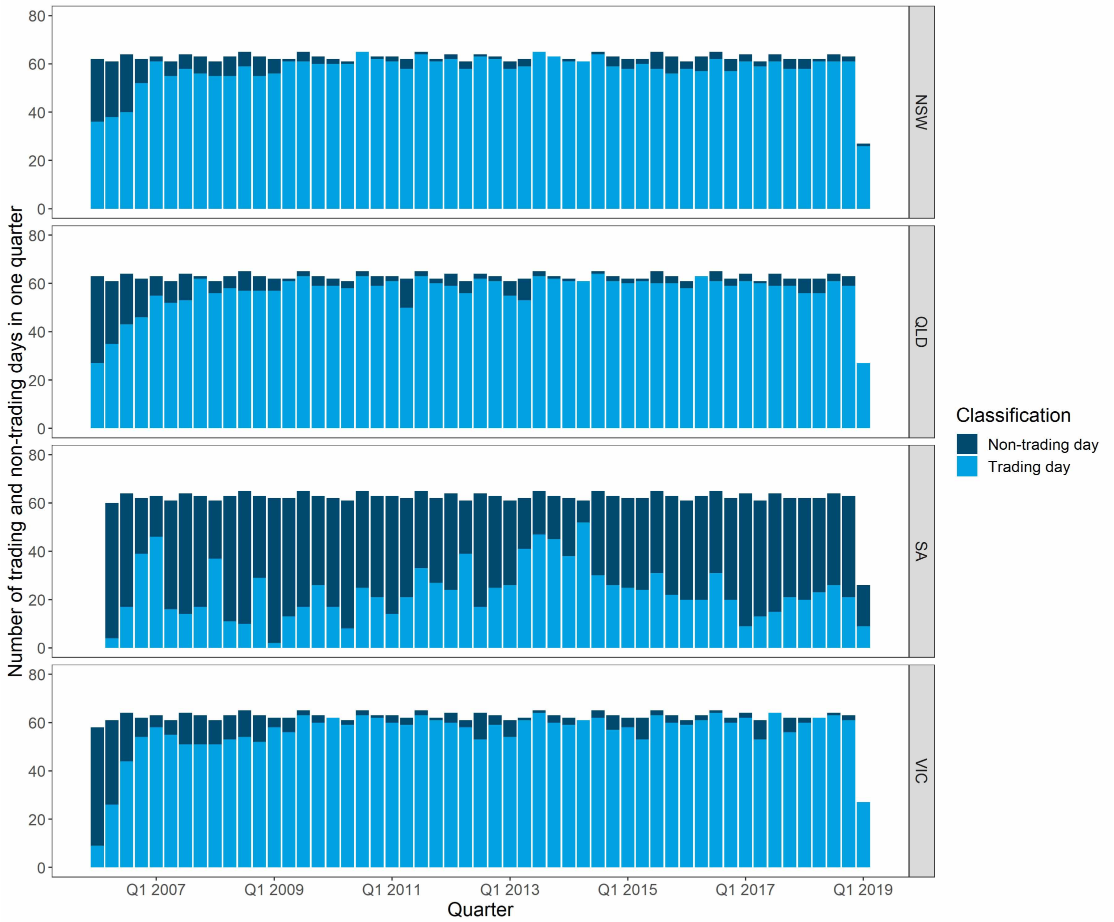
4.2 Liquidity in the NEM

Liquidity is reasonably healthy in Queensland, New South Wales and Victoria, and notably less so in South Australia.

4.2.1 Number of days contracts were traded

Figure 4.1 below shows there were no contracts traded on the ASX on a majority of days in South Australia, whereas there were very few days when no trading occurred in other jurisdictions. This has been a relatively consistent and observable pattern across the data set from 2007. The pattern indicates that market participants are either not making contracts available, or the prices at which contracts are available are not acceptable to counter-parties.

Figure 4.1: Number of days each quarter with no trades



Source: ASX data, AEMC analysis.
Note: The sum of the trading and non-trading days represents the total number of days on which trading could occur.

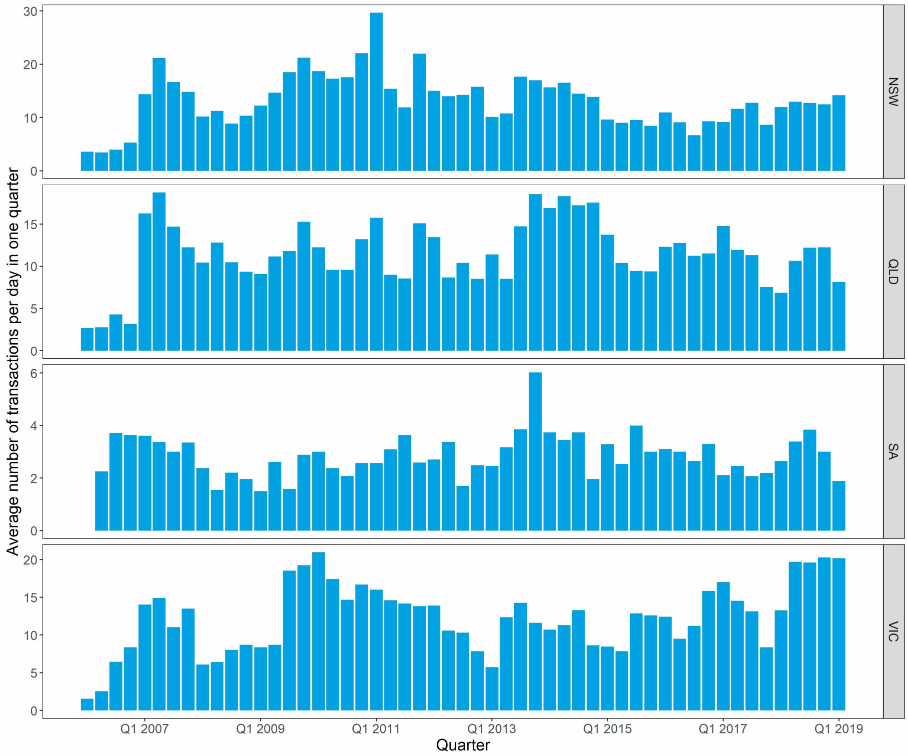
It is anticipated that significant improvement in this metric will be observable after the commencement of the ASX scheme, given the ASX scheme requires market makers to post prices for a majority of trading days, within specified bid-ask spreads.[18] Similarly, if the MLO is triggered in South Australia, some improvement in the metric should be observable, although this will depend in part on how many quarters the MLO is triggered for.

4.2.2 Average number of trades per day

Figure 4.2 below shows the average number of base futures traded each trading day in each quarter in NEM regions, on days where trading has occurred. It is a metric that provides an indication of trading activity and potentially the freshness of prices.

18 The market making agreement requires that market makers make markets in 35 sessions per calendar month except in January and December where the requirement is reduced to 25 sessions.

Figure 4.2: Daily average of base future trades



Source: ASX data, AEMC analysis.

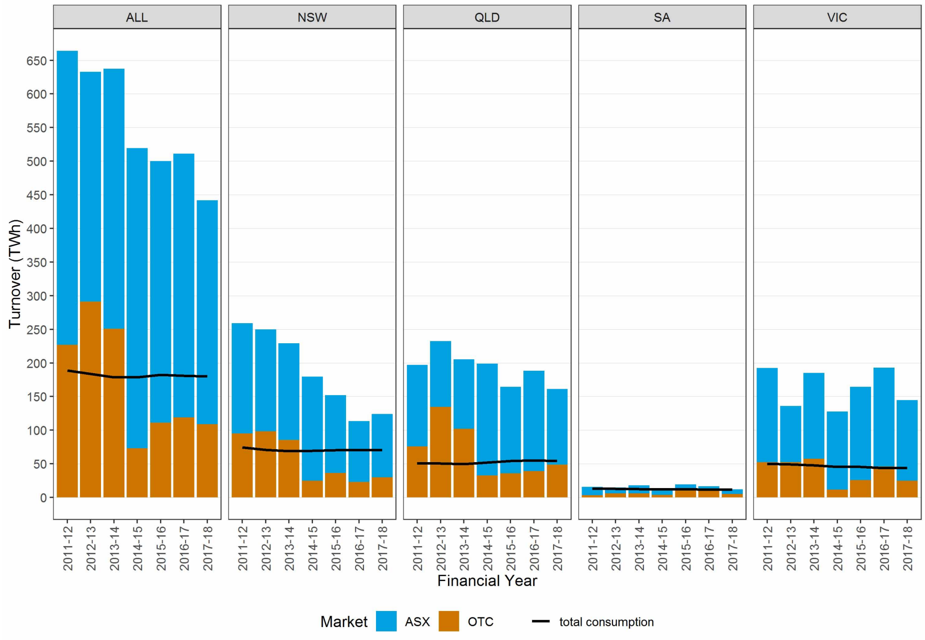
The figure shows there are typically 10 to 20 trades made each day in each quarter in New South Wales, Victoria, and Queensland. In contrast, South Australia typically has two to four trades each trading day. The South Australian trading level has been relatively constant since 2007.

The low average number of trades in South Australia is likely reflective of few offers and prices unacceptable to counter-parties. As with the number of days contracts were traded, the ASX scheme and MLO (if triggered) should deliver observable improvements in this metric.

4.2.3 Trading volume and churn

Figure 4.3 below shows the contract volumes traded in each NEM region. There are notable declines in the more liquid regions of the NEM, particularly New South Wales and Queensland. In South Australia the contract volume has consistently been aligned to levels of demand, reflecting low liquidity.

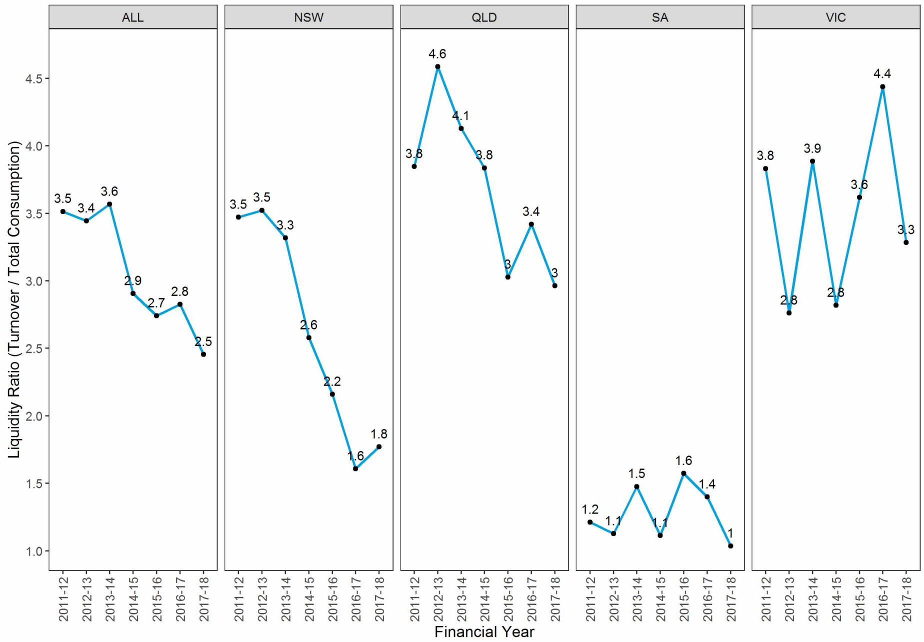
Figure 4.3: Annual volume of contracts (OTC and ASX)



Source: AFMA and ASX data, AEMC analysis.

Another way to assess volumes is with direct reference to demand, using a churn ratio. Figure 4.4 shows declines in churn in all regions recently, and a declining trend over a number of years in New South Wales and Queensland. South Australian churn rates have varied over time, but have remained consistently close to one and less than two. In 2017-18 the churn ratio in South Australia was 1.0 compared to an average of 2.5 across the NEM.

Figure 4.4: Annual churn ratio (OTC and ASX contracts)



Source: AFMA and ASX data, AEMC analysis.

The low levels of churn in South Australia are likely to undermine participant confidence in the contract market This is because 'stale' prices may not be reflective of current market conditions and participants have reduced ability to trade in or out of a risk management position as market circumstances change.

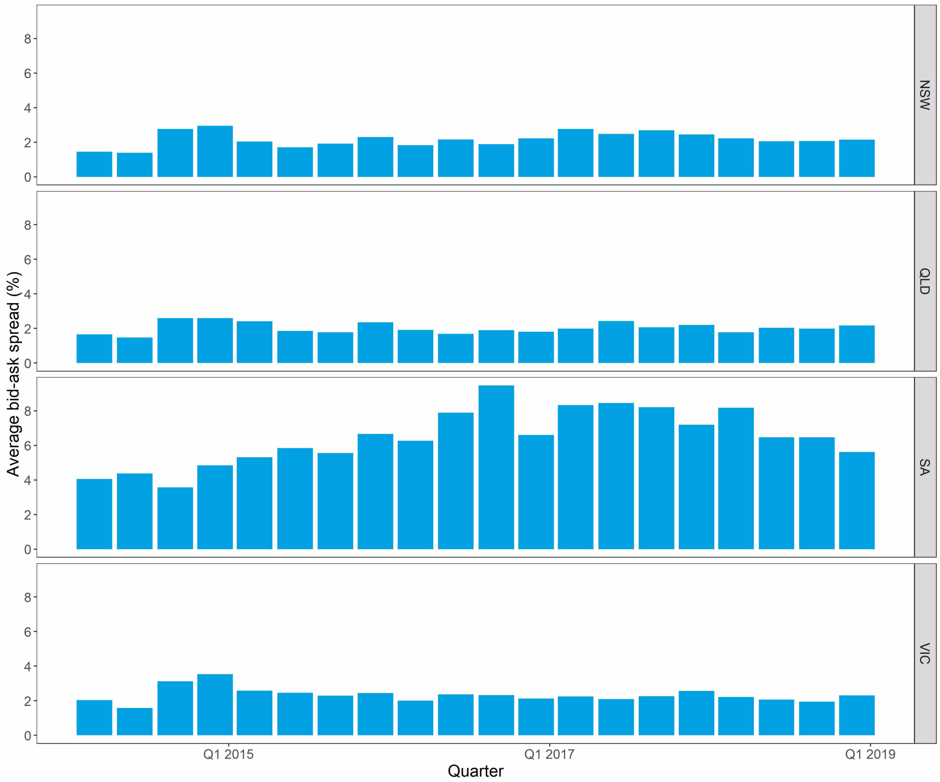
The requirement on participants in the ASX and MLO schemes to post a specific quantity of contracts on a specific number of days within a given bid-ask spread should see improvements in these metrics.

There are also additional structural factors that affect the volume and churn metrics over time. These are addressed in the Chapter 5.

4.2.4 Bid-ask spreads

Figure 4.5 below shows the average bid-ask spreads in base futures in each of the four NEM regions since 2014.

Figure 4.5: Average bid-offer spreads for base futures



Source: ASX data, AEMC analysis.

The analysis above shows that spreads in New South Wales, Victoria, and Queensland have narrowed since 2015 to just over two per cent. In contrast, the average spread in base futures in South Australia typically ranges between six per cent to nine per cent.

The ASX and MLO schemes both specify the spreads that the market makers can use. There is a three per cent spread requirement in New South Wales, Victoria and Queensland, and a five per cent requirement in South Australia. The market making services should therefore have the most observable impact in South Australia.

4.3 Alternative products

There are a range of alternative hedging products that participants use to manage risk. AFMA compiles and publishes an annual *Electricity Derivatives Turnover Report*.[19] The data is sourced from the ASX and a survey of industry participants, and covers both ASX and OTC transactions. This survey was put in place as an alternative to a mandatory report on financial derivatives under Australia's G20 agreements after the global financial crisis.

19 For more information see: https://afma.com.au/data.

The survey results for 2017-18 show that approximately 95 per cent of turnover in the ASX and OTC markets is for swaps (84.7 per cent) and caps (9.9 per cent). The remaining five per cent includes a series of products including day ahead swaptions, OTC caption calls, Asian options, captions and floors.[20] AFMA also report that the OTC market represents 25 per cent of the overall contracts market turnover, and 41.6 per cent of the OTC trades are conducted through brokers.

The AFMA report states that a range of products are not covered in its survey.[21] Participants listed the following alternative products:

- weather insurance and weather caps
- secondary settlement residue auctions (SRAs)
- wind and solar firming products
- load following hedges
- various weather contingent and plant contingent availability derivatives with variable volume and payout characteristics.

These products are typically more bespoke than traditional swaps and caps. For example:

- a load following hedge is a product constructed by the seller from swaps and caps to meet the varying demand levels of a given purchaser
- weather insurance products, and wind and solar firming products, enable intermittent generators to offer firm contracts to customers despite varying generation.

These examples show how the market has adapted to provide the risk management products required, given changes in generation technology and consequent changes in the types of contracts that can be offered.

Various industry participants highlighted the increasing importance of such products as the change in technology from traditional thermal to intermittent generation progresses, and storage options develop. However, no data is available on the relative importance of these products as part of participants' overall risk management.

The Commission also notes that there are other well recognised risk management products that are not captured in ASX data or the AFMA survey.

- PPAs have been the most common form of contracting for intermittent wind and solar generators in recent years. These contracts vary in detail but commonly pay a fixed price for all the output from a generator, even though that volume may vary depending on weather conditions. There is no readily available data on the quantity or price of PPA contracting.
- Demand response contracts are another form of contract that can protect customers from high and volatile spot prices. Similar to PPAs, there is no readily available data on the quantity or price of demand response contracts.

20 ibid

21 AFMA defined this as 'any other non-standard instruments employed that hedge forward electricity price risk that cannot be included in 'any other category' of the standard set of hedging instruments

4.3.1 Industry workshop and survey

In order to better understand the range of contracting products and relative importance of those products, the Commission held an industry workshop in Melbourne in February 2019, and sent a survey to market participants in March 2019.

Participants at the industry workshop noted that:

- as generation and storage technologies become more modular there are opportunities for vertical integration at significantly smaller scale than historically
- PPAs, demand response and SRAs with inter-regional hedges[22] are increasingly common risk management tools.

The Commission sent out a voluntary survey to market participants in March 2019. In part, this was an attempt to quantify the use of alternative products and to gain further perspective on how standard and alternative products are used in a portfolio. The survey was designed to be relatively simple for participants to complete while aiming to provide a high level view of the relative importance of different risk management options.

The survey asked for each business to specify its annual load and generation for each of the NEM reference nodes (with the exemption of Tasmania), and then to provide a percentage split of products used to manage the risks of its load and generation. The product choices included ASX products, OTC products, internal hedging, PPAs, alternative products and unhedged. The survey then asked for the alternative products to be further split into weather insurance and derivatives, interregional hedging with secondary SRAs, wind/solar firming, load following hedges, plant contingent derivatives, demand response and any other products.

Only four participants responded to the Commission’s survey, although a number of other participants met with Commission staff to discuss qualitatively how they manage their electricity wholesale market risk. Given the limited response, the survey results cannot be relied upon as representative of broader trends. Noting this, the insights from the small sample of businesses that responded include:

- most businesses, regardless of their size, used some type of alternate products in managing their wholesale market risk
- PPAs and SRAs are used by larger businesses as a risk management tool for a (not insignificant) portion of their load and/or generation
- demand response can mean both large users reducing their load and/or the aggregation of many small users reducing their demand at the same time. Either way these contracts (mainly internally managed) were seen to be non-firm hedges as there is a low level of certainty if the amount of demand response can be achieved at the time it is needed.

4.4 Conclusion

The Commission's conclusions from this analysis are:

22 An interregional hedge is a contract where the generation is in a different region to the load whose wholesale price risk it was purchased to cover

- ASX and OTC data indicate there has been a decline in liquidity in the NEM between 2016-17 and 2017-18. While liquidity in New South Wales, Victoria and Queensland remains relatively healthy, liquidity in South Australia is low. Notably, the requirements of the ASX market making scheme and the MLO if triggered should see improvement in all the metrics assessed.
- There are material information gaps in relation to the contract market. There is limited data on the volumes and price of important risk management products, in particular PPAs, demand response and weather derivatives. This suggests the AFMA estimate of the size of the contract market is understated, and the regulatory understanding of the market is limited. This is discussed in more detail in Chapter 7.

5 STRUCTURAL CONDITIONS IMPACT LIQUIDITY

This chapter describes the structural market conditions that impact on liquidity in the NEM, particularly in South Australia. It also examines developments that may impact on the South Australian market structure and liquidity in the near future.

In general, liquidity is influenced by the ability and willingness of participants to offer and buy contracts on the supply and demand sides. These are inter-related factors:

- the ability is driven by factors such as the quantity and characteristics of generation, the level of vertical and horizontal integration, the level and characteristics of demand, and the degree of interconnection with other markets
- the willingness is driven by price and volatility.

The supply of firm generation, the underlying spot price volatility, and the levels of vertical integration, demand and interconnection distinguish South Australia from other jurisdictions. In combination, the observed ability and willingness of participants to offer or buy contracts in South Australia is different to other regions. The result is lower levels of contract market liquidity observed over the long term.

This chapter explores these factors and why understanding the influence of structural factors on liquidity is critical when considering market making arrangements. There is potential for the market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker in markets where structural factors reduce liquidity but market making requirements are high. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of the regulatory assessment.

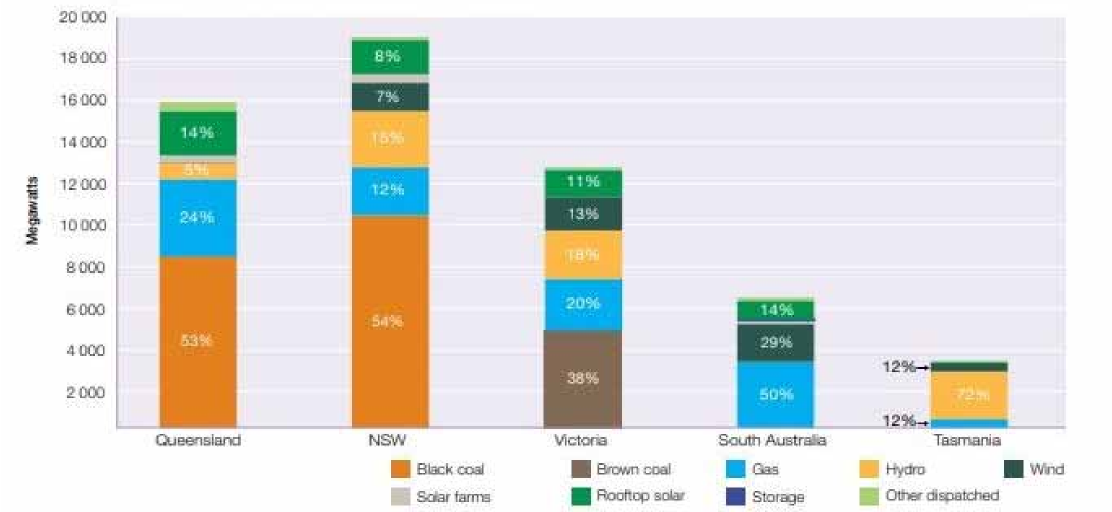
5.1 The supply of firm generation in South Australia

'Firm' generation is generation that is dispatchable and has a high ability to be able to defend (traditional) contracts for a particular delivery period. Examples of firm generation include gas and coal-powered generators, hydro-electric generators and battery storage systems. However, the contracts written by 'firm' generation may vary significantly between technology types.

5.1.1 The proportion of firm generation available

South Australia has less firm generation available than other jurisdictions to meet changes in demand and provide firm hedges. Renewable generation is a large proportion of South Australia's total generating capacity compared to other states, as seen in Figure 5.1. South Australia's higher penetration of renewable generation reduces the available quantity of firm contracts because renewable generators cannot offer firm supply without associated storage or firming infrastructure.

Figure 5.1: Share of firm and non firm generation in South Australia and the NEM



Source: AER, State of the market report 2018, figure 2.6

Note: Generation capacity at 1 July 2018. Rooftop solar output estimates derived from CER data on installed capacity and AEMO system output assumptions. Other dispatch includes biomass, waste gas and liquid fuels. Storage only includes battery storage.

5.1.2 Surplus generation by region

The quantity of firm hedges available in a region is also influenced by the quantity of firm generation that is surplus compared to demand.

South Australia requires imports during peak demand periods if intermittent generation is not generating. This is because firm generation in South Australia (comprising gas, diesel and batteries) made up 2,908 MW out of a total of 4,408 MW registered available summer scheduled and semi scheduled capacity in 2017-18.[23] This level of firm generation is below both the instances of the maximum demand observed in FY14 and FY 17 as well as AEMO's POE10 maximum demand forecasts, which are in excess of 3,000 MW.[24]

In Figure 5.2, generation in South Australia includes wind and solar summer capacity de-rated based on AEMO's 'firm contribution' estimates to account for generation likely to be operational during periods of maximum demand. However, even when de-rated, this capacity is not suited to offering firm hedges. Therefore, South Australia is reliant on interconnection and intermittent generation to meet its maximum demand, which in turn means there is a lack of contract availability for peak demand periods.

23 AEMO, *Generation information page -- South Australia: Summer Scheduled Capacities tab*, 10 May 2019.

24 AEMO, *South Australian Electricity Report — figure 5,* November 2018.

Figure 5.2: Surplus generation capacity by region

Source: AER, State of the market report 2018, figure 2.22.

Note: Maximum demand in financial year minus summer capacity (nameplate capacity for non-scheduled plant) at 31 January in each region. Summer capacity for 2016-17 in Victoria includes Hazelwood, with closure of the plant reflected in 2017-18 data. Wind and solar summer capacity is de-rated based on AEMO's 'firm' contribution estimates to account for generation is likely to be operational during periods of maximum demand.

5.1.3 The role of gas generation in South Australia

Gas is expensive relative to other fuels and the fixed costs associated with gas transport are high for generators operating intermittently or for limited periods. The costs and risks associated with obtaining a supply of fuel for gas generators negatively influences the quantity and cost of hedge contracts available in the market compared to other generation technologies.

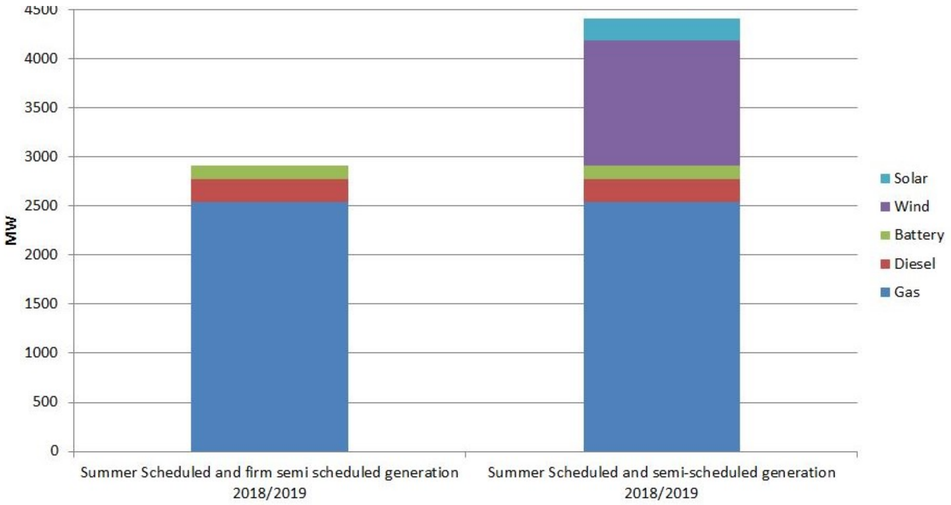
In 2017-18 gas fired generation represented 58 per cent of total available summer generation capacity in South Australia, and 87 per cent of firm capacity.[25] A standalone generator contracting for gas transport in South Australia must recover a fixed gas transport cost from the electricity spot market that they are only likely to operate in for short periods. The high cost of operating gas fired generation in South Australia has been cited as a reason participants are not buying contracts and a cause for some operators to mothball generation units for a time.[26]

Participants' willingness to purchase contracts decreases as the price increases, and their incentive to explore other options (such as behind the meter options or vertical integration) increases.

25 AEMO, *Generation information page -- South Australia: Summer Scheduled Capacities* and *Existing S & SS Generation* tabs, 10 May 2019. Note: firm capacity does not include firm wind or solar capacity as stated by AEMO.

26 https://www.originenergy.com.au/about/investors-media/media-centre/origin-works-with-engie-to-help-boost-energy-security-in-south-australia.html

Figure 5.3: Gas fired generation as a portion of South Australian firm and total capacity



Source: AEMO data, AEMC analysis.
Note: Firm capacity shown excludes de-rated wind capacity.

Reforms recently introduced in the gas market in relation to better access to pipeline capacity should help to reduce transport costs and improve the liquidity of these contracts over time. Nevertheless, the liquidity of transport and commodity gas contracts is an important consideration in assessing the performance of any market making arrangement, particularly in relation to South Australia.

The challenges of contracting gas and gas transport for the supply of firm hedges through gas fired generation is covered in more detail in appendix f.

5.1.4 Vertical integration

Vertical (and horizontal) integration can be rational and efficiency enhancing responses to market conditions. The operational and capital risks of operating across an integrated business may be lower than operating separate businesses. While low liquidity is often attributed to vertical integration, vertical integration can be a response to underlying market conditions which make forward contracting difficult rather than being the cause of low liquidity.

The ACCC's REPI report concluded that in certain regions of the NEM, particularly South Australia, the level of liquidity and the advantages enjoyed by vertically integrated retailers makes it difficult for new entrants and smaller retailers to compete.[27] New entrants cannot win significant market share without securing additional wholesale supply from competitors. There has been an observable reduction in the quantity of contracts available to the market where higher levels of vertical and horizontal integration exist.[28]

27 ACCC, *REPI Final report p.ix.*

28 ACCC, *REPI p.128.*

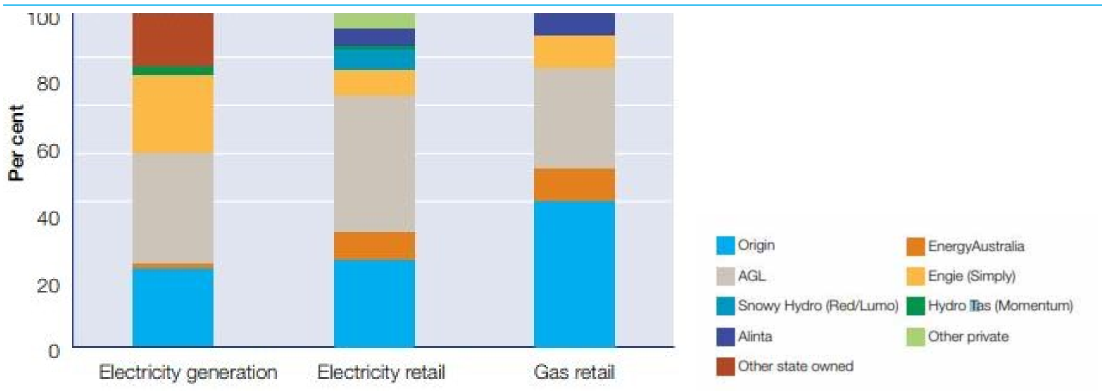
Irrespective of whether vertical integration is the cause or effect of low liquidity, the competitive effects of low liquidity need to be understood and potentially managed. Structural approaches such as divestiture requirements, ownership limits, or compulsory market making provide one set of options. Improved information is an alternative path (see chapter 7 on Transparency).

Of the 2,908 MW of firm generation capacity in South Australia:

- 95 per cent is owned/operated by vertically integrated participants. Only five per cent (130 MW from the Hornsdale and ESCRI batteries) is owned by other participants.
- all firm gas generation capacity is owned or contracted to vertically integrated participants.

Figure 5.4 below shows South Australia's high levels of vertical integration in its electricity generation, electricity retail and gas retail sectors.

Figure 5.4: Vertical integration in South Australia



Source: AER, State of the market 2018.
Note: This graph shows all generation market share for each business, not firm generation.

Vertical integration reduces standalone participant's ability to contract. This is because vertical integration reduces contract volumes, and hence market liquidity, compared to a market with the same generation capacity without vertical integration.

5.2 Demand and spot price volatility in South Australia

Compared to other jurisdictions, South Australia has low levels of demand, with approximately 12TWh of the 196TWh in the NEM in 2017-18.[29] It also has high rooftop solar penetration and a high proportion of installed wind capacity. These factors mean both the demand and supply profiles can change rapidly based on weather conditions.

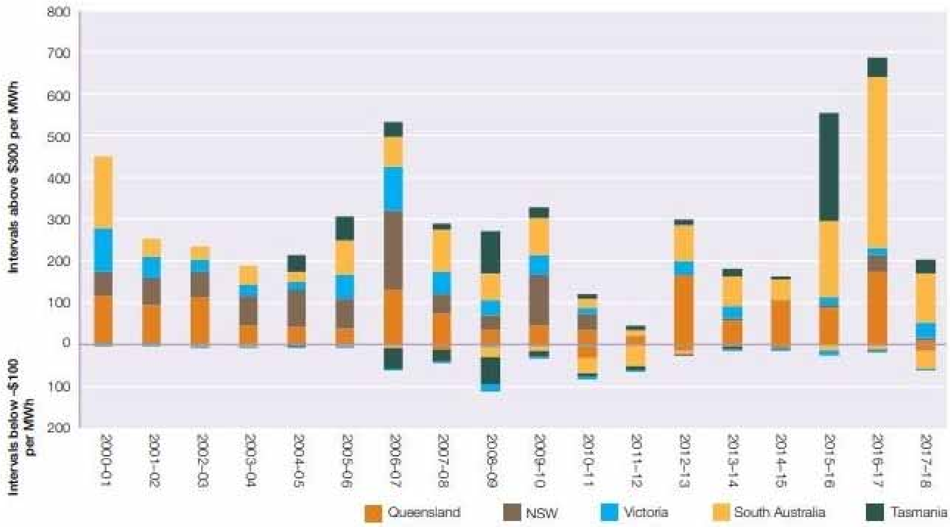
Demand changes and limited firm generation to meet supply can result in highly volatile wholesale spot prices. The interconnection capacity available from Victoria may offset this

29 AEMO, *South Australian Electricity Report*, November 2018, p.18 and AEMO, *The NEM fact sheet*, p. 2.

volatility to an extent, depending on whether there are interconnection constraints in operation.

Figure 5.5 below illustrates that South Australian market has consistently experienced more price intervals above $300/MWh and below -$100/MWh than other jurisdictions.

Figure 5.5: Intervals in the NEM with prices greater than $300/MWh and below -$100/MWh



Source: AER, State of the market report 2018, figure 2.30.
Note: Total number of intervals where spot prices exceeded $300 per MWh or fell below -$100 MWh.

Spot price volatility has a bearing on the willingness of generators to offer firm hedges and the price of those hedges. Generators may be less willing to contract when volatility is high, or they may be unwilling to provide hedges (for substantive capacity), without high premiums. Buyers may then be unwilling to pay those high premiums.

Customers who are faced with high prices have greater incentives to look for alternative lower cost solutions. Alternative products such as interregional hedging, SRAs, weather insurance or demand response, may be increasingly more economic than contracting for firm hedges.

5.3 How are these structural factors likely to change in the future

The structural factors highlighted are all more prominent in South Australia than in other states. The proportion of overall energy that comes from renewable energy, the small size of the market, the limited amount of firm generation, the reliance on gas to provide firm generation, the degree of vertical integration in the market (that may in part be linked to these factors) are all relatively pronounced in South Australia.

The question looking forward is the degree to which these factors might be expected to change. Reforms in the gas market may see reductions in the cost of firm pipeline capacity. Renewable generation as a portion of total energy is likely to increase through continued rooftop solar development and further wind and solar project development. Interconnection is set to increase through the development of the Riverlink interconnector, but this may have a bearing on the continued operation of some firm generation capacity in South Australia.

New battery developments in South Australia, both at a utility level and at a disaggregated level, may provide increased firm capacity. The development of demand response may also have a bearing on the availability of firm hedges. Some new thermal generation capacity is planned. However, in the medium term, the forecast supply-demand balance of firm generation in South Australia appears unlikely to change significantly. As a consequence, the impact of market making on South Australian contract market liquidity needs to be monitored and understood in that structural context.

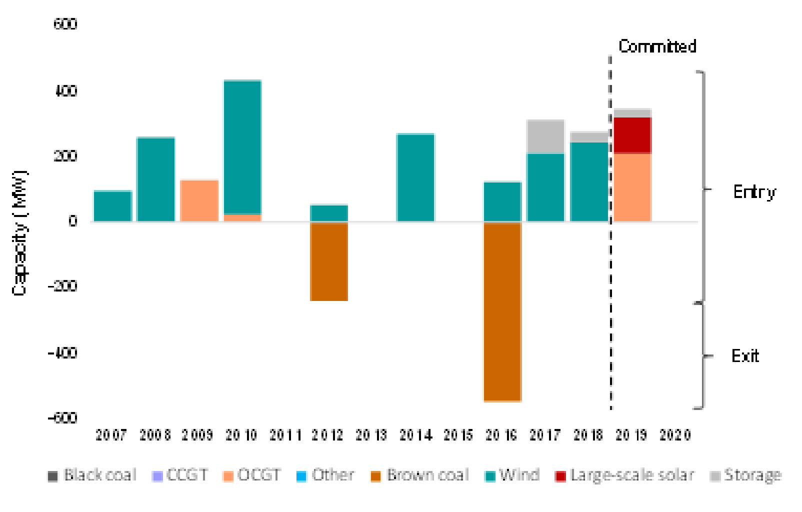
The following sections discuss new developments that may affect liquidity in South Australia.

5.3.1 Generation developments in South Australia

Current registered summer scheduled and semi-scheduled generation capacity in South Australia is 4,408MW.[30] 2,908MW of this is firm generation (gas, diesel, battery storage) with 1,500MW being renewable generation (solar and wind, excluding rooftop PV).

This reflects thermal generation retirements and renewable generation investment in recent years, as shown in Figure 5.6 below.

Figure 5.6: Entry-exit of generation in South Australia (2007 to 2020)



Source: AEMO data, AEMC analysis.

In terms of firm capacity, two large firm brown coal generators closed in recent years. Playford B (240MW) was mothballed in 2012 before closing in May 2016 with Northern power

30 AEMO, *Generation information Page – SA*, 21 January 2019 dataset, viewed on 21 May 2019, https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information

station (546MW).[31] The retirement of Northern was attributed to the high cost of operating with a brown coal fuel source and meant it had to operate in periods where prices were below operating cost for long periods due to the high penetration of renewables.[32]

The gas fired Pelican Point generator (478MW) operated at half its installed capacity between 2015 and 2017.[33] ENGIE cited unfavourable market conditions including higher fuel costs and an increased market share of renewable generation explaining its original decision to mothball one generation unit. The second unit returned to full operation in July 2017 on completion of a gas deal with Origin Energy that is reported to run from 1 July 2017 to 30 June 2020.[34]

In terms of renewable generation capacity, 958MW of new wind and large scale solar generation capacity has been installed in South Australia since 2014.[35] A growing amount of battery storage has been installed with 130MW already in operation and a further 25MW due to be connected in 2019.

Planned developments

Over the medium term (see Figure 5.7 below), the overall level of firm capacity is expected to fall slightly by 2024-25 and the overall level of renewable generation to increase.[36]

31 AEMO, *Generation information Page – SA*, 18 November 2016 dataset, viewed on 21 May 2019.

32 Australian Broadcasting Corporation, *Port Augusta's coal-fired power station closes in South Australia*, 10 May 2016.

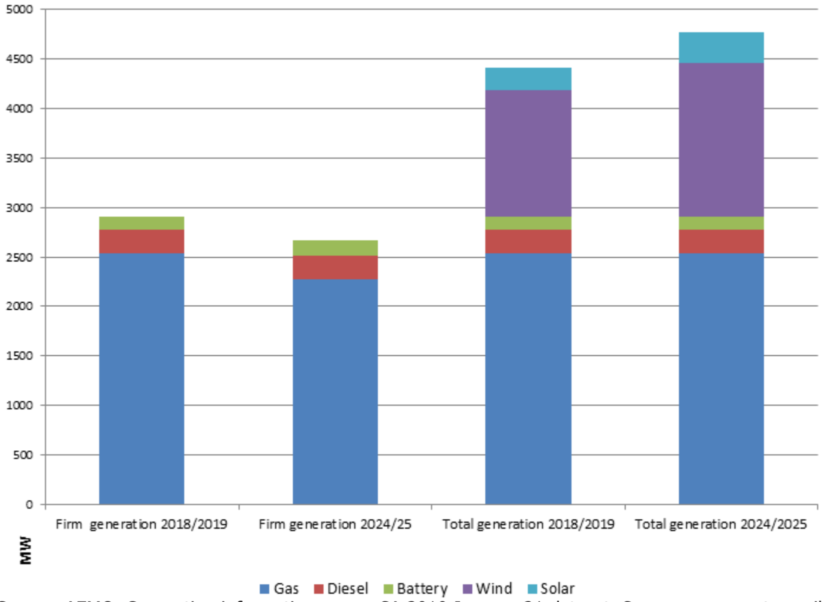
33 AEMO, *Generation information Page – SA*, 18 November 2016 dataset, viewed on 21 May 2019.

34 Origin Energy Ltd, *Origin works with ENGIE to help boost energy security in South Australia*, press release, 29 March 2017.

35 AEMO, *Generation information Page – SA*, 28 February 2014 and 21 January 2019 datasets, viewed on 21 May 2019.

36 AEMO, *Generation information Page – SA*, 21 January 2019 dataset, viewed on 21 May 2019.

Figure 5.7: Firm & aggregate summer capacity in South Australia (2018-19 to 2024-25)



Source: AEMO, Generation information page - SA 2019 January 21 dataset, Summer aggregate available scheduled and semi-scheduled generation tab.

The forecast above includes:

- a reduction in firm capacity driven by the retirement of Torrens Island power station A (TIPS A)[37] and the building of the Barker Inlet (210MW) power station by AGL, providing a net reduction in capacity of 27MW.[38]
- additional battery storage to be added with Lake Bonney Battery Energy storage (25MW).[39]
- additional renewable capacity to be added through committed projects including Lincoln Gap (126MW) and Willogoleche (119MW) wind farms and Bungala Two (110MW) solar farm.[40]
- the SA Government's Grid Scale Storage fund and Home Battery Scheme will also have a bearing on the supply-demand balance for firm hedges in South Australia in the longer term.[41]

Therefore, in the foreseeable term, firm generation in South Australia is expected to remain relatively unchanged. There is no apparent structural change that would signal a material difference in the volume of firm contracts that could be offered in the near future.

37 Two units (240MW) will be mothballed after winter 2019, one unit (120MW) after winter 2020 and the final unit (120MW) after winter 2021.

38 AEMO, *Generation information page - SA*, 21 January 2019 dataset, viewed on 21 May 2019.

39 ibid.

40 ibid.

41 See: http://www.energymining.sa.gov.au/energy_implementation/grid_scale_storage_fund.

5.3.2 The Integrated System Plan

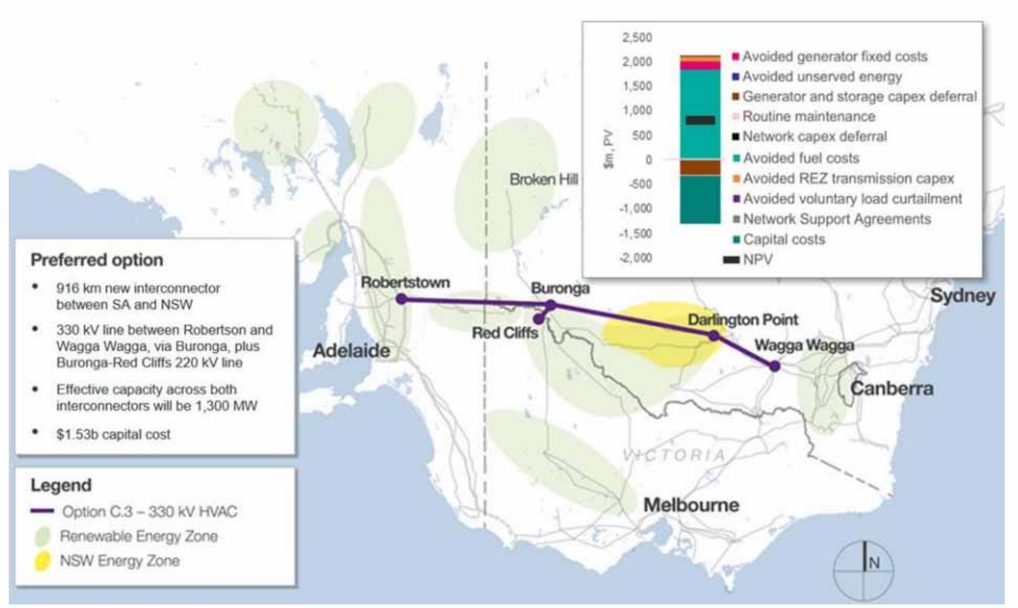
The Integrated System Plan (ISP) was published by AEMO in July 2018. It forecasts the required transmission investments in the NEM over the next 20 years to provide consumers with safe, secure, reliable electricity at least cost across a range of plausible scenarios for the future.[42]

The ISP identified a range of network upgrades to be completed by the mid 2020s, including:

- the RiverLink interconnector between New South Wales and South Australia (750MW) is expected to be operational by 2024[43]
- 100MW increased interconnection between Victoria and South Australia on the Heywood interconnector by 2025 is also being considered.[44]

These upgrades would allow renewable and base load generation in other NEM regions to be imported to South Australia, reducing costs for South Australian customers through fuel savings from reduced demand for gas powered generation (GPG).[45]

Figure 5.8: Preferred option for the route of the NSW-SA interconnector



Source: Electranet, *SA Energy Transformation RIT-T Project Assessment Conclusions Report*, 13 February 2019

42 AEMO, *Integrated System Plan*, June 2018, p.3.

43 Dan van Holst Pellekaan MP, MOU on electricity interconnector, 19 December 2018. Visit at: https://premier.sa.gov.au/news/mou-on-electricity-interconnector

44 AEMO, *Integrated System Plan,* June 2018, p. 9.

45 AEMO, *Integrated System Plan,* June 2018, pp. 87, 94. Fuel costs savings are the key driver for this initiative according to AEMO. AEMO modelling indicates the interconnector would enable GPG in South Australia to be displaced by a combination of coal-fired generation (outside of South Australia) and renewable energy.

5.3.3 The expected impact of RiverLink on liquidity in South Australia

The relationship between the introduction of RiverLink, the retirement of firm generation, and impacts on liquidity, are not clear or agreed. The positions that have been put forward are:

- AEMO has forecast that RiverLink is likely to lead to lower overall utilisation of gas fired generation in South Australia and may therefore promote early retirement of firm generators.[46]
- Conversely, RiverLink may deliver additional firm generation from NSW to South Australia. Snowy Hydro has stated that the removal of interconnector congestion will allow it to offer more firming capacity in South Australia.[47]
- An investor in new renewable generation in South Australia submitted to Electranet that the interconnector improves the business case for generation projects.[48]
- Increased investment in generation, backed by RiverLink is expected to increase tradable capacity in the South Australian hedge market. The alignment between the preferred route of the interconnector and two renewable energy zones identified by the ISP will help facilitate the development of new renewable generation.[49]
- Electranet considers the retirement of conventional generation in South Australia over the next decade is unrelated to the development of RiverLink, and sees the project as a remedy to potential generation shortfalls, rather than as a driver of early retirements.[50]
- One participant noted that inefficient gas plants are unlikely to be competitive in the medium to long term and are expected to exit the market regardless of Riverlink.[51]
- The potential for interconnector failure could also be a limiting factor on liquidity. According to CQ Partners, RiverLink's double circuit configuration makes it less likely that it would fail, meaning the risk to hedge markets is relatively small, potentially strengthening confidence in interregional hedging strategies.[52]

From this range of perspectives, it is not clear what impact additional interconnection will have on the availability or price of firm contracts offered into the market.

46 AEMO, *Integrated System Plan,* June 2018, pp. 26, 40, 47.

47 Snowy Hydro, *Submission to Electranet*, 30 August 2018

48 Electranet, *SA Energy Transformation*, p. 44, CQ Partners, *SA-NSW Interconnection,* p. 48.

49 AEMO, *Integrated System Plan,* June 2018, p. 50.

50 Electranet, *SA Energy Transformation*, p. 35.

51 CQ Partners noted that it is likely that these less efficient plants will exit the market regardless of whether interconnection occurs or not. CQ Partners, *SA-NSW Interconnection,* p. 3.

52 CQ Partners, *SA-NSW Interconnection,* p. 7.

6 COST BENEFIT ANALYSIS OF MARKET MAKING SCHEMES

This chapter describes the approach taken to estimate the costs and benefits of market making options, and NERA's key findings from its analysis. The chapter covers:

- the background and approach used in assessing the market making options
- assessing the costs and benefits of the options
- the costs of market making schemes
- the benefits of market making schemes
- conclusions on the net benefits of additional market making arrangements.

6.1 Background

In assessing this rule change, the essential question for the Commission was whether additional market making beyond the ASX market making scheme and the MLO, would be efficient and contribute to the NEO. In order to assess this question, the AEMC put forward four broad market making options for consideration in the consultation paper. These options were to:

- not make a rule, but monitor the effectiveness of the ASX and RRO/MLO schemes
- have a centralised tender process, as proposed in the rule change request
- have a trigger driven obligation
- have a compulsory market making requirement.

The Commission engaged NERA to conduct a qualitative and quantitative assessment of the costs and benefits of these options with a view to establishing two things.

- Firstly, to establish the new baseline level of liquidity that will be delivered via the ASX market making scheme and the RRO/MLO.
- Second, to calculate the incremental costs and benefits of the other options, including the solution put forward by the proponent. This analysis would then inform whether additional market making was required, and if so, what form the additional market making arrangements should take.

The NERA report describes the analysis undertaken and is available on the project website.

An additional market making model was raised with the Commission after it had engaged NERA to complete this modelling exercise. This model is a variation on the compulsory market making model assessed, except it only requires generators to offer contracts to the market, rather than bids and offers. The model is described and qualitatively assessed in Appendix D.

6.2 Assessing the costs and benefits of the options

The assessment framework that was set out in the consultation paper was also used by NERA in its quantification of the incremental costs and benefits of each market making option. This assessment criteria includes consideration of the extent to which market making will create costs and benefits in relation to:

1. enhancing transparency and predictability
2. enhancing wholesale and retail market competition
3. efficiency of investment in, and retirement of, generation and demand response
4. administrative costs.

In the rule change proposal the proponent observed that market making arrangements have been proposed and introduced internationally without a firm basis for the intervention. These international market making schemes are briefly described in Appendix C and more fully in the NERA report.

NERA agreed with this observation and noted that a consensus has not been reached about how to define liquidity, how much is enough and how liquidity should be measured. It is also the case that market making arrangements have been introduced without a detailed cost benefit analysis of the options, given the challenges of such analysis. The work that NERA has completed should be considered in the context of this challenge, noting the necessity of simplifying the operation of the market in order to provide a reasonable basis for quantification of the benefits.

NERA observed in its analysis that while the costs across international schemes are similar, and therefore easier to quantify, the benefits of market making obligations internationally have been largely elusive and difficult to quantify. The counter-factual is difficult to establish, that being the level of liquidity that would have occurred without a market making requirement. Additionally, all market making schemes internationally have been accompanied by a number of other market reforms designed to improve competition. Isolating the specific impact of market making is therefore difficult.

6.3 The costs of market making schemes

The costs of market making schemes internationally are broadly similar. They largely comprise fixed costs in relation to staff and the administration of trading and also variable costs in relation to the costs of collateral and taking sub-optimal or loss making positions from the perspective of the trading firm.

Market making costs are higher during periods of high volatility and when the obligation places tighter constraints on market makers. In designing the market making obligation, there is a trade off between ensuring that market making is provided during periods of high volatility (the benefits of price signals are greatest during these periods) and ensuring that market makers do not bear excessive costs to provide market making during these periods.

Given the trading provisions under the ASX voluntary market making scheme have converged on those required under the MLO, the costs of providing market making under each scheme considered in the cost benefit analysis are largely similar.[53] The costs of market making in the

53 The compulsory market making option assumes the MLO conditions would apply at all times, even though the MLO will only apply in periods the RRO is triggered.

NEM, are based on internationally observable costs adjusted to take account of the higher volatility of the price of electricity contracts in Australia.

The key sources of difference in the costs of each scheme are as follows:

- in the ASX voluntary scheme, market makers can suspend market making during periods of volatility, which will reduce the variable cost of market making.
- the centralised tender process may have lower costs as it enables the participation of financial traders who may be the most efficient market makers. However, the Singapore experience highlights that an inefficient tender design, could result in high costs.
- the trigger driven obligation may have lower costs than a compulsory market making scheme because it is only operational when triggered. In the NEM, this may effectively translate to compulsory market making on an ongoing basis in South Australia, and no other region, depending on the metric used to trigger the obligation. For the purposes of the analysis, NERA assumed, where the obligation is triggered, it is only triggered in the regions where the liquidity metrics have fallen short of the benchmarks set.
- the compulsory obligation may have higher costs if it results in less efficient market makers being selected. It may also distort competition in the market over the longer term, increasing regulatory risk and discouraging investment in generating capacity by those who are subject to the scheme.

The regulatory costs of the incentivised tender, triggered obligation and compulsory obligation are also assessed.

The distribution of costs and who bears them may differ between schemes in the short term. For example, the compulsory scheme imposes costs directly on physical participants, while a centralised tender process passes costs onto consumers or non market making parties.

6.4 The benefits of market making schemes

NERA assessed the benefits of each scheme on both a qualitative and quantitative basis.

In qualitative terms, the benefits of market making are that at it addresses issues arising from insufficient liquidity. Insufficient liquidity may impede price discovery, entrench market power, create information asymmetry between market participants and result in inconsistent price signals between the spot market and the contract market. All these factors may make it difficult for smaller and new entrant retailers to compete in the market effectively. By improving the transparency and predictability of forward prices, market making may strengthen wholesale and retail competition, and provide signals for efficient investment.

In quantitative terms, NERA identified the key changes likely to result from a market making arrangement, and how those changes would impact on the operations and costs of retailers and generators. Specifically, improvements in the bid ask spread lower transactions costs for retailers and generators but also encourage increased hedging and a consequent reduction in the amount of risk capital, and the cost of risk capital, required for a retailer to compete.[54]

54 NERA's assumption of greater hedging refers to a greater level of hedging using the swap products that form the market making scheme.

These competitive effects can be observed through the trade-off that market participants may make between hedging in forward markets and exposing themselves to additional price risk in the spot market.

To perform this quantification NERA constructed a simplified balance sheet for a representative retailer and then ran simulations to examine the implications of changes in electricity prices and customer churn. NERA modelled the impact of the availability of contracts at narrower bid-ask spreads on the optimal hedging strategy. They found that suppliers tend to hedge more when hedges are available at a narrower bid-ask spread.

Lower transactions costs achieved by a market making arrangement therefore result in two categories of benefit:

- a direct financial benefit to competing generators and retailers on the volume that they trade
- allowing generators and retailers to hold fewer assets on their balance sheets to insure themselves against insolvency. Holding fewer assets offers a benefit to market participants equal to the cost of capital or required return on those assets.

NERA's modelling is necessarily an abstraction from reality and includes a number of simplifications, for example:

- the hedging strategy of a representative supplier was used, rather than the individual portfolios of specific retailers. It was also assumed that generators are the counter-party to retailer trades. In practice, this is likely to understate the benefits of a market making arrangement where generators trade frequently or trade between themselves.
- only quarterly contracts were analysed. More rarely traded contracts, such as monthly products, were not considered sufficiently indicative data for the analysis.
- the results assume market participants can hedge their entire position at the lower bid ask spread on mandated products. In practice, spreads across the range of products used, both within and outside a market making arrangement, may not all be at the mandated level.

The degree to which these benefits are delivered depends on the degree of compliance to the scheme specification (trading windows, volumes, bid ask spread) that is assumed, including during periods of high volatility.

6.5 Conclusions on the net benefits of additional market making arrangements

NERA concluded that each option has a range of possible net benefits. However, provided the ASX scheme delivers the benefits intended, then there is no additional benefit from adopting additional market making arrangements, irrespective of whether additional intervention is in the form of an incentivised tender, a triggered obligation or a compulsory obligation. This rests on the assumption that market makers comply to the design of the voluntary arrangement and therefore that the benefits in relation to the bid ask spread and the availability of prices and contracts are delivered.

It should be noted that the designs considered in the analysis are all largely consistent, in the products required, lot sizes, market making periods, and bid-ask spreads, and as a result they all have largely the same impact on the market. The comparative results therefore distinguish between market design options, rather than representing assessments of alternative levels of obligation. For example, the bid-ask spreads are not materially tighter in one option than another.

In practice, the different designs may be more or less effective in delivering narrower bid-ask spreads in the wholesale market. Market participants have the option of withdrawing from the ASX scheme periodically over time. Therefore, in principle, the liquidity benefits of this scheme could be lower than the other schemes. However, if the ASX scheme results in a similar market outcome to the other designs, then the net benefits of the ASX scheme could be expected to be greater because it presents cost savings relative to the other designs.

Where the designs lead to a step change in liquidity, as shown in the "MMO+Liquidity" case in the report, the benefits may be significantly greater. However, provided the voluntary ASX scheme achieves what it is intended to do, then this would be the lowest cost option to achieve this outcome.

The net benefits of all the options are greatest in South Australia. This is because the requirement to post regular prices and the required reduction in the bid-ask spread provide for the greatest improvement in transactions costs compared to currently observed levels.

The benefits of the market making arrangements tend to be correlated with costs, under the assumptions used for the analysis. High benefits to market participants equate to higher costs for market makers. This is because the benefits are greatest when market makers make markets at the prescribed spreads during periods of high spot and or contract price volatility. The costs are also greatest in these periods.

Figure 6.1 below summarises the net benefits of each scheme.

Figure 6.1: NERA costs and benefits of market making in the NEM

Table 1: Estimated net benefits of the proposed MMO designs

		[1] ASX MMO + MLO		[2] ENGIE's Incentivised MMO		[3] Trigger Driven MMO - SA Only		[4] Mandatory MMO	
	Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Benefits	MMO	10.3	26.3	10.3	26.3	5.2	12.6	10.3	26.3
	MMO+Liq.	22.4	56.0	22.4	56.0	12.2	28.6	22.4	56.0
Costs		13.7	18.6	17.3	19.6	5.9	6.3	17.1	19.2
Net Benefits	**MMO**	**-3.4**	**7.7**	**-7.1**	**6.7**	**-0.7**	**6.3**	**-6.8**	**7.2**
	MMO+Liq.	**8.7**	**37.3**	**5.0**	**36.4**	**6.4**	**22.3**	**5.3**	**36.8**

Source: NERA Analysis

Source: NERA

It should be noted that in incremental terms, none of the additional schemes were assessed to add net benefits above the voluntary ASX market making scheme, assuming the ASX scheme delivers the benefits it is intended to.

Figure 6.2 provides a summary of the incremental benefits from market making in situations where the ASX scheme delivers the benefits intended.

Figure 6.2: Incremental net benefits of additional market making

Table 5.7: Incremental net benefits from ASX MMO plus MLO – No dropping out

		[1] ASX MMO + MLO – No dropping out		[2] ENGIE's Incentivised MMO		[3] Trigger Driven MMO - SA only		[4] Mandatory MMO	
	Scenario	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	*High*
Benefits	MMO	0	0	0	0	0	0	0	0
	MMO+Liq.	0	0	0	0	0	0	0	0
Costs		0	0	0.7	1.0	0.5	0.5	0.5	0.5
Net Benefits	**MMO**	**0.0**	**0.0**	**-0.7**	**-1.0**	**-0.5**	**-0.5**	**-0.5**	**-0.5**
	MMO+Liq.	**0.0**	**0.0**	**-0.7**	**-1.0**	**-0.5**	**-0.5**	**-0.5**	**-0.5**

Source: NERA Analysis.

Source: NERA

Note: Table assumes base ASX MMO+MLO case delivers all the benefits intended under these arrangements

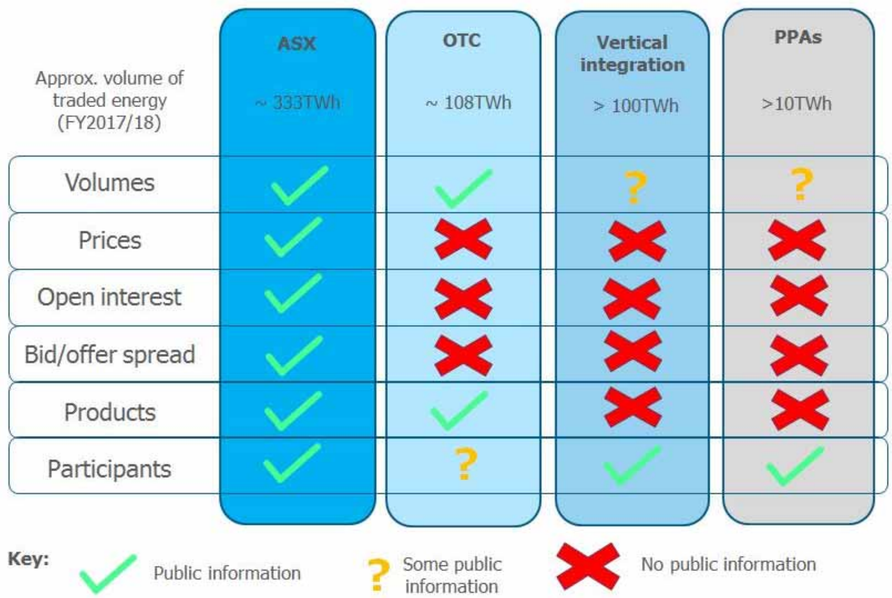
7 TRANSPARENCY

In the course of examining liquidity it became apparent that there are material information gaps in the contract market. The gaps undermine price discovery for market participants, and the assessment of market conduct and performance by regulators.

Contracts are traded on the ASX, bi-laterally (OTC) and internally (vertical integration).[55] The visibility of these trades varies, with good visibility on the ASX, limited visibility of OTC trades, and no visibility of vertically integrated transactions. Traditional hedging products such as swaps and caps are generally visible on the ASX. Newer forms of contracting such as PPAs, demand response contracts and weather derivatives are not traded on the ASX and have lower or no visibility.

Figure 7.1 below maps the availability of information on contracting. It shows the market visibility of key contracting dimensions and estimated volumes against the type of contract.

Figure 7.1: Information map - NEM contract market



Source: ASX and OTC volumes are as per ASX and AFMA figures for 2017-18. PPA estimate based on wind and utility scale solar output at the end of 2017-18. Vertical Integration assessment is based on generation output from vertically integrated retailers. AEMC analysis.

Given that demand in the NEM in 2017-18 was 196TWh, Figure 7.1 shows:

- **ASX** — most contracting is conducted on the ASX, and the details of these trades are the most visible to market participants.

55 The nature of the internal agreements that vertically integrated participants use is not visible and may not be uniform. All such arrangements are referred to as contracts in this draft determination.

- **OTC contracts** — represent approximately one third the volume of ASX trades, based on AFMA data. However, as noted in chapter 4, the AFMA data under-states the actual level of OTC contracting. For example, it does not include data on PPAs, demand response, weather derivatives or secondary SRA trading. There is also a lack of data on prices, so these trades do not directly assist existing or prospective market participants in price discovery.
- **Vertical integration** — estimated volumes are notable in that they exceed 50 per cent of total market demand, although it is noted that these internally contracted volumes may be traded (multiple times) on the ASX and OTC to optimise a participant's contracting position.
  - There is no market visibility on the form of contracts, volumes or prices of these contracts. This has led many smaller retailers and commercial and industrial (C&I) customers to question whether the prices they pay for contracts as an external party are reasonable (competitively equivalent) compared to those available within vertically integrated firms. Uncertainty in this regard may undermine participants' confidence in the contract market and contribute to an unwillingness to buy or sell contracts, given market confidence is a key characteristic of liquid markets.
  - The ACCC did examine this issue using its information gathering powers as part of the REPI, and concluded that there was general equivalence between internal contracting and contracts offered to external parties. This 'point-in-time' finding may give participants improved confidence to enter into contracts. Notably the AEMC has not had access to the ACCC data.
- **PPAs** — have been the most common form of contract for underwriting investment in renewable generation. While some contractual details may be reported, there is no systematic reporting of key contractual data.

The information gaps make price discovery for smaller market participants and prospective entrants difficult and may undermine confidence in the contracting market. The gaps also make it difficult for regulators to assess the conduct of market participants and market performance.

The remainder of this chapter describes how to address the information gaps identified.

7.1 Improving price discovery

The ACCC's REPI recommended the establishment of an OTC repository so that all OTC trades would be disclosed publicly in a de-identified format.[56] The ESB has recently consulted with industry on this recommendation, and provided recommendations to the Energy Council on this issue.[57] It considered a preferable path is for the AEMC, AER and market participants to work with AFMA to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

56 See ACCC, REPI, recommendation 6.

57 The ESB provided advice to the Senior Committee of Officials on 19 May 2019. The Energy Council had not responded before this draft determination was finalised.

The ESB supported its recommendations with reference to the following factors:

- the OTC market is a subset of market data and information on OTC trades is available to market participants via brokers
- there are challenges with providing the market with meaningful data given the bespoke nature of some OTC contracts
- the costs of an OTC repository may be significant.

These factors are described in the following sections.

7.1.1 OTC data and availability

As noted above and in Chapter 4 on liquidity, the OTC data reported by AFMA under-states the level of bi-lateral contracting in the market. PPAs, demand response, all forms of weather derivatives, wind and solar firming products, secondary trading of SRAs, and load following hedges are not captured in the current AFMA survey. In aggregate, these products are likely to comprise a material volume of contracts. This is particularly the case in South Australia, where the high penetration of intermittent renewable generation means these products are relevant and suited to participants' hedging requirements.

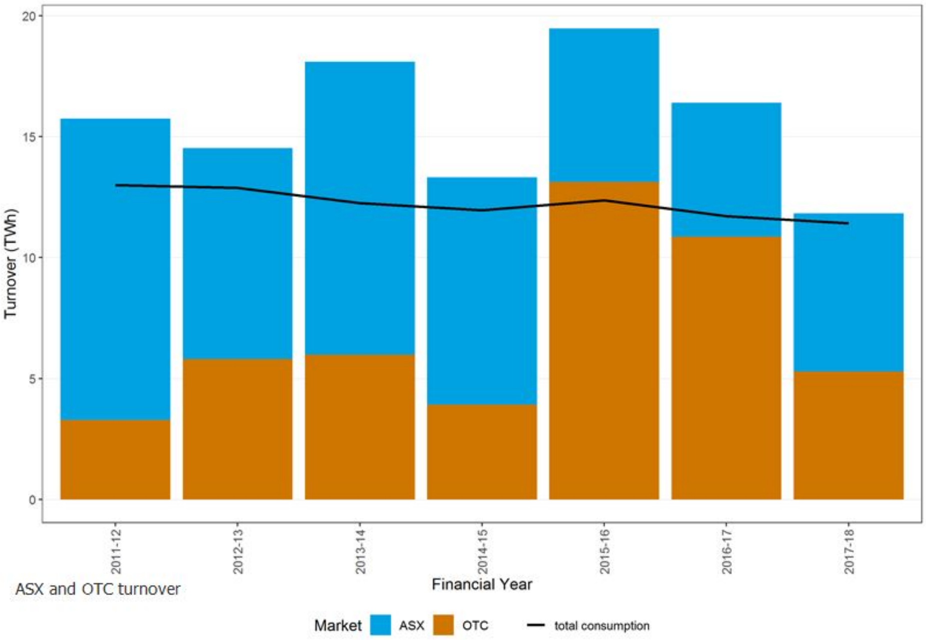
Some information on these products may be available to participants via brokers. The AFMA survey indicated that OTC products (excluding those identified above) represented 25 per cent of 2017-18 contract market volumes, and 41.6 per cent of the OTC contracts were transacted via brokers.[58] If it is considered that the contracts transacted by brokers are visible to the market and represent approximately 10 per cent of the total contracting market,[59] there is still approximately 15 per cent of the market that is not visible. Given the gaps in the AFMA data, in particular in relation to PPAs, demand response and weather derivatives, the Commission considers the non-visible portion of the contract market may be materially larger than implied in the AFMA data.

It is also notable that the volume of contracting between the ASX and OTC varies over time and by jurisdiction. This means the visibility of contract market data will also vary. For example, in South Australia, OTC trading comprised over two-thirds of contract market activity in 2015-16 and 2016-17, although it can be materially lower in other years. This is shown in Figure 7.2.

58 See https;/AFMA.com.au/data.

59 41.6 per cent of 25 per cent is 10.4 per cent.

Figure 7.2: Reported OTC contract turnover in South Australia



Source: AFMA data, AEMC analysis.

The Commission also looked at the availability of information from brokers.

Participants can access broker services in two broad ways, they can:

- subscribe to the broker service, and receive daily updates on contract market prices that the broker has access to
- engage a broker for assistance with a specific transaction.

The Commission understands there are six to seven major brokers operating in the market, and subscription services cost between $20,000 and $30,000 per annum per broker. Small and infrequent traders will likely find these services too expensive, and will instead rely on advice on a per-transaction basis. Larger participants with more frequent trading activity may subscribe to a number of or all of the services.

A further consideration is that the types of contracts currently not captured by the AFMA survey are likely to be the contracts increasingly needed as technology continues to shift to intermittent renewable generation and customers have an increasing ability to invest behind the meter in generation and demand response technologies. In short, given current industry trends, contract data availability is likely to diminish rather than improve in the near term unless additional data capture mechanisms are developed.

It is also important to acknowledge that while the majority of OTC contracts are reasonably standard swap and cap contracts, other OTC contracts cover more bespoke products such as load following hedges. The Commission accepts that data on load following hedges would only be useful to the market if the market had information on the shape of the load being hedged. This is also the case for other non-standardised products. However, the difficulty of defining meaningful data for reporting should not exempt such data from consideration for reporting, and there is an opportunity for industry to provide leadership on such issues. It is noted that New Zealand has operated an OTC repository for a number of years, and a number of participants at the AEMC industry workshop indicated they would like access to more data and were capable of analysing it themselves.

7.1.2 Addressing gaps in the OTC data

The ESB recommendation on OTC visibility is for the AEMC, AER and market participants to work with AFMA to improve the transparency of the OTC market. It also recommended that the effectiveness of the AFMA survey be reviewed after a suitable period.

Towards this goal, and reflecting the analysis undertaken in this rule change, the Commission has identified specific areas where improvement is required for the AFMA survey to provide adequate transparency of OTC trades. These include:

Price

There is no price information in the AFMA survey. It is the main item that needs to be addressed in order for OTC data to address the price discovery needs of the market.

The Commission understands this will also be the most contentious item for AFMA and its members to address. AFMA will need to obtain the agreement of members to collect and publish pricing data, and it is concerned about potential legal liabilities in publishing reference prices.

Coverage

There is scope to improve industry participation and product coverage. There were only fourteen participants in the 2017-18 AFMA survey, although they represented the majority of market generation and load, and the two main financial traders.

The material product gaps in the survey have already been noted. In working with the AER, market participants and AFMA on improving the AFMA survey, threshold levels of participant and product coverage will need to be agreed.

Timeliness

The AFMA survey is conducted annually and released some months after the end of the financial year. This limits the usefulness of the data to industry, and means it would not be useful for price discovery even if it contained pricing data.

The Commission considers that at least monthly data would be necessary if the data was to be useful for price discovery.

The Commission is aware that more frequent reporting would necessitate a change from AFMA's current largely manual processes to an automated system. There would certainly be costs in changing to an automated system, but the Commission questions the level of such costs. Market participants that trade regularly already capture trading data in their internal risk management systems. The costs of making this data, or some portion of this data, available for AFMA reporting seem unlikely to be material.[60] For market participants that trade irregularly, the administrative costs of submitting data seem unlikely to be high.

Implementation and effectiveness

The Commission agrees with the ESB that the effectiveness of an improved AFMA survey should be reviewed after a suitable period. The Commission also considers there is a need to specify the time for improvements to be made. Improvements may occur in stages, if this is the path agreed by the AEMC, AER, market participants and AFMA. However, it is important to agree some threshold issues in the near term. Such issues include whether the key dimensions of pricing data, coverage and timeliness can be addressed by the AFMA survey process. These threshold decisions should be made before the end of 2019.

7.2 Improving regulatory assessment of market performance and conduct

The ACCC's REPI recommended an expansion of the AER's market monitoring function to include the contract market, and enhancing the AER's information gathering powers.[61]The ESB also examined this recommendation and supported the ACCC's position in its advice to the Energy Council. It recommended that the AEMC and AER work to draft law changes required to give effect to the AER's expanded role. The recommended law changes are to be provided to the Energy Council.

In the course of this rule change the Commission has identified specific AER monitoring and reporting that it considers should be enabled by the proposed law changes, while noting that the changes to give effect to the breadth of the ESB recommendation may be broader than these specific items. The specific changes are described below.

7.2.1 Monitoring compliance with market making schemes

The AER should monitor the compliance of the market makers in the ASX market making scheme in a way that is consistent with its monitoring of participants' compliance with the MLO if triggered. Understanding compliance with the scheme will be an important input into understanding whether the scheme is delivering sufficient liquidity. The absence of clear compliance data would cloud analysis of whether the scheme design was sufficient and efficient in delivering liquidity. Therefore, compliance monitoring is critical.

Appendix E shows the key requirements of the ASX market making scheme compared to those of the MLO. The scheme designs converged in the last few months of development and are now closely aligned on most requirements. As the AER is already preparing to monitor compliance with the MLO, it should be relatively simple to extend this compliance coverage to include the ASX scheme, although it is noted that the ASX scheme will run continuously

60 The work related to the implementation of the Consumer Data Right is premised on Application Protocol Interfaces (APIs) being available at low cost to enable data from disparate company systems to be made centrally available.

61 see ACCC, REPI, recommendation 41

whereas the MLO will only apply in relation to periods where a reliability gap has been forecast.

The Commission understands that market makers in the ASX scheme will receive a monthly compliance report from the ASX on whether they met the terms of the market making agreement. The key terms relate to whether the market maker offered the required product volumes during the required market making periods at the specified bid-ask spreads. If the market makers comply then they are eligible to receive the scheme incentive payments, including exchange fee rebates and a share of profit associated with the growth in trading that the market making scheme delivers.

The AER will not have automatic access to the ASX compliance report for market makers, nor does it have powers to compel the ASX to provide specified data. The AER will therefore have to require compliance data directly from participants, or come to an alternative arrangement with participants and the ASX.

7.2.2 Monitoring and reporting on market liquidity

As part of its expanded role in monitoring and reporting on market liquidity, the Commission considers the AER should at least take account of the following factors:

- the levels of compliance achieved in the ASX market making scheme and the MLO if triggered
- the liquidity factors examined in this rule change process, including; the availability of prices, the bid-ask spreads, the number of days with trading, the number of trades and trading volumes
- the structural characteristics of each jurisdiction.

Market makers' compliance

As noted, an understanding of whether compliance with a market making scheme has occurred is a pre-requisite to assessing whether the scheme design is sufficient and efficient. A record of participant compliance over time will be important in determining the success of the ASX and MLO schemes over time.

Liquidity factors to monitor

There are a wide range of liquidity metrics that could be monitored. However as described in Chapter 4, the key metrics relate to:

- the availability of contracts, measured by the number of days market making services are available, and the volume (and lot size) of contracts made available each day
- the price of contracts, as measured by the bid-ask spreads
- trading volumes and churn and the number of trades.

Structural characteristics of each jurisdiction

Chapter 5 described how structural market conditions affect liquidity. The AER will need to account for structural differences in different jurisdictions in its ongoing assessment of, and reporting on, liquidity. As noted, in markets where structural factors reduce liquidity to low levels, but market making requirements are high, there is potential for the market making requirement to merely shift risk from non-hedged or under-hedged participants to the market maker. Assessing the reasonableness of any market making requirements against the structural market conditions is therefore an important part of the AER's monitoring task.

7.2.3 Reporting by large vertically integrated participants

In relation to the assessment of market performance and conduct in the wholesale and contract markets, it is noted that there is not a standard information base against which to assess whether large vertically integrated participants are exercising market power. Instead, there has been a series of one-off studies into market performance and conduct, including: the ACCC's REPI, the AER's Hazelwood advice,[62]the Grattan Institute's report on gaming[63] the Victorian Energy Policy Centre's report into market power, [64] among others. These studies are in addition to more regular reporting by a number of Commonwealth and jurisdictional agencies.

Despite the lack of regularly available data, a number of studies have proposed or examined structural solutions to the market, such as divestiture powers, ownership limits, underwriting of investment, and operational separation.

As a general principle regulatory mechanisms and responses should escalate in a manner that is proportionate to the risks and impact of particular market conduct. As large vertically integrated participants are corporations with significant market power and their conduct can have material and widespread impact on a market and consumers, it is reasonable that higher levels of regulatory scrutiny and stronger sanctions may be applied to such corporations.

An example of regulatory escalation is the differentiated requirements that can apply to corporations under the following:

- market and operating information requirements
- accounting separation
- operational separation
- ownership separation (divestiture).

The 2018 Prohibiting Energy Market Misconduct Bill includes ownership separation powers, and the ACCC examined and rejected operational separation in the REPI. Nevertheless, recent detailed work has not been done on whether additional standardised information should be available to the regulatory agencies to assess the performance of the wholesale and contract markets, and the conduct of participants.

In the course of this rule change, the Commission has not attempted to examine the potential range of information gaps and additional information requirements that may be

62 March 2018

63 Mostly Working Australia's wholesale electricity market, July 2018.

64 The exercise of market power in Australia's National Electricity Market following the closure of the Hazelwood Power Station, 2019.

applied. At this time, it is therefore not recommending the implementation of an accounting separation regime or other more onerous alternatives.

However, the Commission does consider two specific areas are worth further consideration. The two specific areas for potential reporting by large vertically integrated participants are:

- information on internal pricing and contractual conditions compared to external pricing and conditions for contracts to third party retailers or third party generators. This data would inform questions of fair dealing or equivalence between a vertically integrated participant's internal and external contracting
- information on contracting volumes compared to generation availability and capacity utilisation including the degree to which capacity is reserved for internal risk management. This data would inform questions about withholding in the contract market.

These issues are commonly raised but there is poor data availability to enable assessment. The AEMC will examine these more closely in conjunction with the AER as part of developing the required law changes to enhance the AER's market monitoring role.

If this information were reported, it could be made available to regulatory agencies rather than market participants. It would therefore not be an aid to price discovery. The information would help regulatory assessments of market conduct and performance and may help to lessen industry concerns about the exercise of market power by larger participants. This may lessen the need for additional ad hoc inquiries into the industry. An additional indirect market benefit may also be an increase in participants’ confidence in market prices from large vertically integrated participants given the awareness of ongoing regulatory visibility of contract pricing and availability.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Securities Exchange
Commission	See AEMC
MCE	Ministerial Council on Energy
MLO	Market Liquidity Obligation
NEL	National Electricity Law
NEO	National Electricity Objective
NER	National Electrictiy Rules
REPI	Retail Electricity Pricing Inquiry
RRO	Retailer Reliability Obligation

A SUBMISSIONS ON ISSUES RAISED IN CONSULTATION PAPER

This chapter summarises the key issues raised by stakeholders in response to the consultation paper. These issues have been grouped into the following categories:

- defining the problem and identifying the solution
- the range of market making options
- the solution proposed in the rule change request
- the range and specification of products to be included
- jurisdictional specific issues
- commencement dates

A.1 Defining the problem

A.1.1 The proponent's view

The proponent maintains that the justification for market making, in South Australia or more broadly, has not been adequately addressed. The inability of retailers to obtain the hedges they desire at the price they desire is not evidence of market failure. The proponent argues that proposals for market making are based on South Australian market conditions, where liquidity is weaker than in other jurisdictions. It considers the characteristics of the South Australian market have not been taken into account, and the South Australian market does not provide adequate evidence of the need for market making. It also questions claims that whether vertical integration and the withholding of capacity by vertically integrated participants is to blame for liquidity issues in the market. The proponent concludes that there is little evidence that this is the case, especially in circumstances where prices are increasing.[65]

A.1.2 Stakeholder views

Problems with liquidity

In addressing problems with liquidity, many stakeholders felt liquidity in the contract market was not an issue, except in South Australia, where liquidity problems are caused by structural factors in the market, including the limited number of generators offering firm hedges in a small market.[66]

Stanwell referred to these structural factors in South Australia as being worse than other regions due to the withdrawal of capacity, decreasing fuel availability, increasing amounts of variable renewable generation, increasing levels of vertical integration, and the region's reliance on Victoria for imports.[67]

65 Rule change request p.4
66 EA submission p.3, Origin Energy submission p.1., Meridian Energy submission p.2., Snowy Hydro submission p.3.
67 Stanwell submission p.3.

The reliance on gas generation for firm capacity was also referred to by Alinta and Ergon. Ergon stated that a higher share of baseload generation will generally translate into better availability of firm contracts.[68]

Complaints about the lack of liquidity may be influenced by retailer decisions to take spot price exposure according to some participants. Snowy Hydro suggested that contracts are available if negotiated well ahead of dispatch, but the price is sometimes not amenable to the buyer and the choice to take spot exposure is not always positive.[69]

AGL stated the evidence does not support the conclusion that liquidity is declining. AGL argues that the main driver for discussions of market making has been high prices, which are not driven by liquidity but rather than the tightening supply and demand balance. AGL maintained that market participants are not withholding contracts, there are just few fewer generators capable of providing firm contracts compared to recent history. Where liquidity has been impacted, this is a reflection of the uncertain regulatory environment and increasing credit obligations which arise from increased policy and regulatory risks, according to AGL.[70]

Alinta Energy maintain that they presently have no problems in regularly opening or closing out contractual positions across any of the products listed for trade on the ASX across various jurisdictions. Alinta point out that they may not always be able to gain the exact contracts for the exact duration and price that suits their requirements, however on balance, they feel the market is liquid enough to manage the requirements of a medium sized Gentailer business. Alinta do not subscirbe to the view that liquidity in South Australia is a material and ongoing concern.[71]

Ergon Energy said that vertical integration can create barriers to retailers hedging their risk, but a lack of liquidity is also caused by a number of other issues such as: the ASX placing high margins for credit risk (thereby impacting the ability of retailers to trade in the market); block trades on the ASX reducing contract availability and price discovery for market participants; and, a lack of physical interconnection in some regions impacting liquidity and interregional contracting.[72]

The range of alternative products used by participants was also referred to, including SRAs and inter regional hedges, meaning the measures of liquidity in standardised products may not be sufficient to understanding how small and new entrant retailers manage risk.[73]

A number of parties including ERM Power, the ACCC, the EUAA and the South Australian Government did identify problems with liquidity in South Australia. ERM power pointed to a decline in contract market activity in recent years, and maintain that no single factor is to blame. ERM pointed to the ACCC REPI conclusions on declining liquidity in South Australia and declining levels of liquidity in New South Wales.[74]

68 Ergon Energy submission p.3.
69 Snowy Hydro submission p.2.
70 AGL submission p.1.
71 Alinta submission p.2.
72 Ergon energy submission p.2.
73 Stanwell submission p.3.
74 ERM Power submission p.2.

The ACCC stated that low levels of liquidity act as a barrier to entry in South Australia. It maintained that the introduction of the RRO means the contract market will take on even more importance, and should the voluntary market making obligations fail to be effective then the consequences for retail competition will be significant.[75]

The South Australian Government Department of Energy and Mining referred to the AER's 2018 State of the Energy Market Report which noted trading levels in South Australia are below demand levels, which the AER noted, is consistent with claims by retailers that the region's contracting market is highly illiquid. [76] The department also referred to references by the AER of declining liquidity across the market and the role vertical integration has played in this.

How is liquidity best measured?

Alinta referred to the ability to regularly open or close a position across a variety of contract market products. Meridian has a similar definition, describing sufficient liquidity as the ability to enter contracts over time to manage portfolios in the lead up to spot quarters. The AER in its submission referred to liquidity as the ease of buying and selling over time, and stated that this is difficult to quantify.

ERM power submitted that a liquid market provides ample opportunity for buyers and sellers to manage their contract positions. In its view the threshold for a liquidity trigger should be set at 1.5 times underlying demand in a region. ERM also maintained that measures of liquidity should exclude exchange for trade (EFP) transactions where existing exchange traded products are converted into OTC contracts.[77]

Stanwell described a liquid market as one in which, no single transaction is likely to move the price excessively, individual trades are able to be easily executed, large volumes can be traded in a short space of time and the market can recover to its natural equilibrium after being exposed to shocks.

Origin suggested liquidity is where a trade can occur quickly without affecting the assets' price and factors to assess liquidity include churn, volume, bid ask spreads, the number of counter-parties, and the number of transactions over any given period.[78]

The importance of liquidity

Ergon and the ACCC both considered contract market liquidity as necessary for a competitive environment.[79]

ERM power considered that liquidity supports retail competition by allowing participants to manage spot price risk without owning their own generators. This helps to improve outcomes for customers through more secure prices, and greater choice in the retail market. In time, alternative risk management tools such as demand response or aggregated battery storage

75 ACCC submission p.2.
76 SA Government department of Energy and Mining submission p.1.
77 ERM Power submission p.3.
78 Origin Energy submission p.2.
79 Ergon Energy submission p.2.

may become available and economical for small participants and new entrants. However, in the present environment, ERM stated that the contract market represents the simplest and most effective risk management tool available to market participants. Given this, it is important that small participants not be locked out of markets due to a lack of contract market liquidity. As such, market making arrangements imposed on large vertically-integrated gentailers represent the best tool available to enhance contract market liquidity in regions where there is a problem.[80]

Alinta maintained liquidity is an essential component in ensuring participants obtain the risk management products they need. Liquid contract markets also ensure a constant demand for any surplus contracts a participant may have to sell back to the market as part of their normal portfolio optimisation activities.[81]

Meridian Energy maintained that there is little evidence that increased liquidity in financial markets, which trade out three years, will promote increased investment in new generation, given investment horizons are greater than twenty years. They consider the current level of investment in generation is healthy and the contract market is evolving with PPAs increasing significantly in recent years possibly reducing the requirements for traded financial contracts.

Origin maintained liquidity in the contract market does not provide a complete picture of how market participants manage risk. Origin noted that with increasing interconnection in the NEM, there should be greater access to SRAs to manage inter-regional price differentials. Weather derivatives can be used to supplement cap contracts to help manage high demand. The growth in PPAs, particularly those used by C&I customers, enables them to offset their demand. Demand response coupled with strategic spot market exposure is another effective risk management tool. Load following and other bespoke hedges are also used. These products, according to Origin, can all create synthetic generators enabling participants to protect themselves from spot market risk, much like the contract market has traditionally done. These tools may gain in prominence as the market evolves.[82]

The South Australian Government Department of Energy and Mining referred to the impact of liquidity in South Australia on retailers, with many citing the limited access to competitively priced risk management products as a barrier to entry or expansion.[83] The department also referred to the importance of liquidity given the future operation of the RRO in South Australia. A mechanism that will improve liquidity would likely assist liable entities in South Australia to meet their obligation and to do so at lower cost.

Solutions to the problem of low liquidity

Ergon argued for a solution that introduces new participants into the market through incentives rather than obligations on existing participants. Ergon also suggested a reduction

80 ERM Power submission p.2.
81 Alinta submission p.1-2.
82 Origin Energy submission p.2.
83 SA Government department of Energy and Mining p.1.

in ASX fees would significantly help retailers' ability to trade efficiently through improvements to cash flows and reserves.[84]

Snowy maintained that when the NEM supply demand balance is tight there is no unused capacity that can be "conjured up" by regulation. Snowy cited recently announced plans to increase South Australian interconnection by 800MW with the commissioning of the RiverLink project by 2024. This interconnection will provide a benefit by unlocking additional generation resources in the Murray River and Riverland areas.[85]

Snowy also concluded market concentration is likely to fall across the NEM with the growth of renewable generation and the closure of Liddell.[86]

Snowy Hydro further agreed with the proponent's concerns that the justification for market making obligations in South Australia has not been adequately assessed to date. Snowy maintained that hedging in South Australia should be analysed with reference to the characteristics of a small market with a high penetration of renewables, relatively high importance of interconnection and a reliance on gas generation to provide firm capacity.[87]

AGL similarly maintained that introducing a formal market making arrangement will not address the issues in the underlying market (such as investment in new firm generation capacity). Requiring liquidity for the sake of liquidity will not assist with the higher wholesale electricity spot prices that have evolved in recent years.[88]

Alinta made the recommendation that the South Australian and Victorian markets could be merged. Alinta considered such a reform would increase contract liquidity in both regions and whilst it would turn inter-regional constraints into intra-regional constraints, suggests this may be more palatable for participants. Alinta maintained that this is not dissimilar to issues currently in North Queensland. Such a reform is not without precedent, for example the Snowy Region.[89]

Origin maintained that market making should not be seen as a universal fix for liquidity given the structural factors seen in South Australia and the exit of coal-fired generation in the state. Origin states it is important to recognise the high dependence on non-firm renewables and interconnected energy in South Australia. This makes it more difficult to underwrite firm hedges, increasing the likelihood of lower contract market liquidity in the region compared to other states.[90]

Origin argued there should be realistic expectations of what any market making scheme can achieve. Market making addresses the incentive for some participants to engage in the market, but participants already have an incentive to engage in the market (to manage their price risk). Other factors that could be addressed are coal generators reaching the end of

84 Ergon Energy submission p.3.
85 Snowy Hydro submission p.3.
86 Snowy Hydro submission p.5.
87 Snowy Hydro submission p.3.
88 AGL submission p.2.
89 Alinta submission p.2.
90 Origin Energy submission p.2.

their life, and increasing amounts of renewable generation (which increases energy volumes contracted under PPAs, which in turn are often complemented by demand response and storage rather than traditional contract market products). Origin also noted that prudential requirements when trading futures on the exchange can prove challenging for smaller participants and as such, these participants may use other risk management tools.[91]

ERM power maintained that market making and increases to underlying liquidity will allow parties such as independent retailers and financial institutions to access contracts, and as a result offer more risk management products, enhancing competition in risk management tools thereby supporting retail competition.[92] ERM also questioned whether gas supply issues limit an ability of market makers to offer contracts.[93]

A.2 Range of market making options

In the consultation paper the Commission identified a range of potential market making options.

The options range from no rule being made and the market relies on the introduction of the ASX and MLO schemes, to a mandatory requirement that directs specific physical participants in particular jurisdictions to make contracts available within certain contract periods and on specific terms.

The costs of each option may vary according to the level of prescription in the arrangement. The costs may include, but not be limited to, administrative costs, the cost of the bid offer spread or other incentives required to ensure market making is provided over selected contract periods.

The range of options was described in the consultation paper, but included:

- not make a rule, but monitor the effectiveness of the ASX and RRO/MLO schemes
- have a centralised tender process, as proposed in the rule change request
- have a trigger driven obligation
- have a compulsory market making requirement.

A.2.1 Proponent's view

The proponent stated a compulsory scheme will not necessarily increase the total capacity to manage risk in the market, and it may increase costs to consumers if retailers have to contract with lower credit counter-parties.

The proponent pointed to the operating constraints and physical limits market makers will face in making more capacity available, including the constraints imposed by an illiquid gas market. The proponent suggested there is a portfolio benefit to risk management within an integrated portfolio that does not exist for external trade. Above all, the proponent considers

91 Origin Energy submission p.3.

92 ERM power submission p.3.

93 ERM power submission p.5.

it is not appropriate for obligated parties to take on unnecessary costs. Market making should not force obligated parties to trade at a loss.

The proponent further referred to the possibility that the lot sizes of a market making scheme may be too large to assist the small retailers it is intended to help. [94]

The proponent considered the collapse of the market making scheme in the United Kingdom, which has compulsory obligations, is indicative of the issues that may arise in the NEM with a compulsory obligation.[95]

The proponent argued that compulsory market making may undermine the business case for those participants who were willing to provide a market making service under the ASX market making scheme.[96]

The proponent suggests that shareholder and investor expectations are undermined by compulsory market making, placing a further risk premium on investment in specific or all regions of the NEM, given obligated parties must account for unmanageable risks and unrecoverable costs.[97]

A.2.2 Stakeholder views

Comments supportive of proposals

There was broad industry support for relying on existing processes, particularly the ASX voluntary market making scheme, either to solve the issue of liquidity or because of the belief that there was no issue with liquidity in the first place. Ergon Energy, Meridian Energy, Snowy Hydro, AGL and Origin Energy all subscribed to a combination of these views. Snowy Hydro maintained that a voluntary scheme is less interventionist and may increase both liquidity and transparency.[98] Snowy Hydro also argued that should a voluntary proposal proceed then the obligation should be removed from the guarantee[99] and replaced with one of the market based approaches.[100]

The AEC argued that the process of assessing market making options should be delayed in order to assess the outcomes from the voluntary market making scheme. The AEC argued that any need for market making is likely to be transitory and will be impacted by the regulatory, technical and commercial evolution of the market. Further, a voluntary scheme will have more flexibility to encompass innovative products and parties willing to be market makers.[101]

94 Rule change request page p.8
95 Rule change request p.10.
96 Rule change request p.8.
97 Rule change request p.16.
98 Snowy Hydro submission p.5.
99 this is referring to the NEG
100 Snowy Hydro submission p.6.
101 AEC submission p.2.

AGL argued for a watch and learn approach to observe the impact of the ASX voluntary process on liquidity. AGL argued if the scheme is unsuccessful, the AEMC could use the experience to build, design and implement an incentivised scheme.[102] The AER submitted any additional mechanisms should be complementary to and not substitutes for the MLO.

Energy Australia, Alinta and Stanwell were all supportive of the rule change proposal in relation to a tender for voluntary market making services.

Alinta considered that commercial arrangements entered into voluntarily maximise economic welfare and efficiency and also reduce the overall risk profile within the NEM. Participants who seek to participate in a mutually beneficial contractual arrangement are best placed to determine their own risk and commercial appetite based on market expectations and their own unique business requirements. Alinta maintained the tender approach allows for a consistent framework allowing the ASX, brokers and others to compete on a transparent basis, where participants are not obligated to operate beyond their risk tolerance, compliance costs are lower, participants are not forced into contracts with poor credit parties, third party market makers may enter the process and costs can be recovered from the parties that use the service. Such an approach, according to Alinta, is consistent with the free market philosophy of the NEM.[103]

Energy Australia considered that the tender process might incentivise additional parties to take part in market making over and above physical participants.[104] Energy Australia also considered that a centralised tender process was preferable to the MLO as it would encourage additional parties to take part. EnergyAustralia stated a tender process would ensure market making was provided in a transparent, fair manner with appropriate cost recovery, and that it would allow market makers to offer contracts that suit their underlying portfolios and risk appetite. It would minimise the risks associated with compulsory market making and it would not undermine market and investment signals by placing further risk premiums on investment in specific regions.[105]Stanwell did note that a voluntary scheme would be ineffective if some large participants can free ride on the benefits of liquidity created by others without privindg liquidity themselves.[106]

Snowy Hydro noted that the Singapore approach, of all the international approaches, would be a less interventionist approach that seeks to increase the transparency of activities in the contract market without seeking to address potential market power concerns in contracting markets. The introduction of such a mechanism if mandated would still be a substantial change from the light-touch regulatory approach currently adopted in the NEM.[107]

Origin was not supportive of a tender process given the processes already under way with the ASX scheme.[108]

102 AGL submission .p.4
103 Alinta submission p.3.
104 EA submission p.2.
105 EA submission p.4.
106 Stanwell submission p.4.
107 Snowy Hydro submission p.5.
108 Origin Energy submission p.1.

ERM Power favoured a trigger driven obligation that is imposed on large vertically integrated players when contract market liquidity drops below a threshold level.[109] ERM maintained that a trigger based mechanism would enhance transparency and competition in the wholesale and retail markets without imposing direct costs on consumers.[110]

The ACCC and EUAA were both supportive of compulsory market making. The ACCC expressed concerns about the ability of voluntary schemes on their own to address the concerns expressed in the REPI report.[111] The EUAA supported this option as a result of concerns around liquidity in South Australia, and also the potential impacts of the RRO obligation. The EUAA believe an obligation is critical to ensure retailers and large customers have access to sufficient contracts, to enhance liquidity and to provide the price discovery that is unlikely to occur in the absence of an obligation.

Comments in opposition to proposals

In opposing a voluntary market making scheme, the AER submitted that they did not consider the voluntary scheme would be effective in improving liquidity. They also held the view that the operation of a tender, attributed to them by the proponent in the proposal, would be onerous.[112]

In opposing the tender solution put forward by the proponent, Meridian Energy maintained that a trading exchange such as the ASX is best placed to run a market making scheme, rather than the AER.[113]

In opposing a compulsory obligation, both Energy Australia and Ergon stated that an obligation on physical participants is unlikely to increase the number of contracts available to the market as participants are unlikely to offer more contracts than their risk appetite allows.[114] EA also argued that a compulsory mechanism may reduce liquidity across the trading day, by focusing liquidity in the compulsory trading window. Further, it will not solve the structural conditions in the market in South Australia.[115]

Snow Hydro strongly opposed compulsory market making maintaining that the NEM does not need further market intrusion. The obligation is likely to encourage financial misbehaviour by participants trying to exploit competitors' enforced buy/sell market making obligations.[116] It is unlikely to "conjure up" additional capacity and will impose large trading risks with no improvement on liquidity, as shown in UK.[117] Snowy maintains the global examples illustrate that forcing vertically integrated firms to trade like standalone businesses had little or no impact on liquidity. Measures in NZ and UK have not improved either liquidity or competition and the additional regulation has likely depressed liquidity. In the UK, five participants are

109 ERM Power submission .p.3
110 ERM power submission p.5.
111 ACCC submission p.1.
112 AER submission p.1.
113 Meridian Energy submission p.2.
114 EA submission p.3. and Ergon submission p.3.
115 EA submission p.3.
116 Snowy Hydro submission p.2.
117 Snowy Hydro submission p.5.

required to cross-subsidise their competitors' risk management activity at an annual cost of some 20m GBP and yet Ofgem data indicated churn in the electricity market had not improved.[118]

Snowy Hydro explained that mandatory market making would be extremely problematic for peaking plant such as hydro generation and open cycle gas turbines. For instance, it is unclear what the opportunity cost of their generation may be and gas generators would have fuel risks with volume and transportation issues. As a result, forcing an entity to post tight bid/offer swaps up to its registered capacity is inefficient when the opportunity cost of energy-limited plants is changing all the time, and short term spot gas prices can vary significantly on a daily basis. A compulsory obligation would simply increase risk to the gentailer which ultimately is passed through to consumers. It also risks inefficient use and misallocation of scarce resources for fuel-constrained plant, worsening consumer outcomes.[119]

EnergyAustralia and Meridian Energy did not consider the benefits to consumers of this option would outweigh the costs.[120] [121]

Snowy Hydro maintained that a compulsory market making mechanism would be the highest cost of all the approaches listed.[122]

The AEC maintained that if participants are forced to enter into trades with smaller counter-parties with low credit ratings and no credit risk premium, the additional risk will need to be transferred to the participants’ other counter-parties, with a consequent increase in costs for them. This results in inequitable treatment of counter-parties, with the effect that those counter-parties with a higher credit rating will subsidise the lower credit rating participants. According to the AEC it may also impinge upon organisational risk management policies (such as counter-party concentration), and risk compliance with fiduciary duties.[123]

Origin argued that mandatory market making will result in inefficient outcomes, and should not be pursued. It has the potential to distort the market and have unintended consequences. Origin raiseed concerns from the UK example that market making is likely to draw liquidity away from other parts of the day. Origin noteed the UK also saw an increase in compliance costs on obligated parties due to prescribed bid/offers spreads during periods of volatility, which made it difficult for the market maker to manage their own position. [124]

AGL also expressed concerns with compulsory market making, particularly where it forces a tight bid offer spread, believing this will have unintended consequences. AGL expressed support for the proposition that obligations on unwilling participants will increase costs and may limit the participation of financial market participants, due to the removal of commercial

118 Snowy Hydro submission p.4.
119 Snowy Hydro submission p.5.
120 EA submission p.5.
121 Meridian Energy submission p.2.
122 Snowy Hydro submission p.6.
123 AEC submission p.2.
124 Origin Energy submission p.3.

incentives to make markets. AGL stated compulsory market making is neither necessary nor prudent.[125]

Stanwell noted that good market design should promote liquidity and price transparency, not attempt to deliver specific price outcomes.[126]

A.3 Proposed solution

A.3.1 Proponents view

The proponent suggested that a tender run by the AER for voluntary market making services in the NEM[127] is the most appropriate method for identifying parties who have the sophistication and appetite to take on the risk associated with a market making service.

The proponent recommended a tender be conducted every three to five years, covering all regions of the NEM and remaining in place on an ongoing basis, with no trigger mechanism. The proponent recommended the tender be open to financial and other providers of market making services, and that market markers should be permitted to sub-contract directly with physical and financial market participants in order to provide the market making service.

The proponent proposed that the cost of the tender be recovered from customers and that their be penalties for not complying with the arrangement.

The proponent also stated that the AEMC should review the operation of the arrangements in advance of each tender.

A.3.2 Stakeholder views

Energy Australia recommended a one to two year term for the tender, and that the AER run a separate tender for each region with costs recovered from the customers in each region.[128]

Stanwell recommended the tender apply for three years, to align with the market for wholesale contracts and the terms for generator closure requirements. Stanwell maintained the tender should be open to physical and financial participants and sub contracting of responsibilities should be allowed. Stanwell considered costs should be appropriately tiered to the size of participants and that the chosen exchange should also contribute.[129] Stanwell maintained monitoring and review of the market making arrangement should be the responsibility of the AER.

Ergon Energy maintained the costs of the tender should not be recovered from customers.[130]

AGL suggested the tender should be operated by a body with experience regulating financial markets, such as the ASX. This would help to minimise administrative costs as market

125 AGL submission p.2.

126 Stanwell submission p.3.

127 Rule change request p.8.

128 EA submission p.4.

129 Stanwell submission p.5.

130 Ergon Energy submission p.4.

participants have already developed systems to integrate with the ASX, whereas an entirely separate process may lead to duplication.[131]

Origin considered the penalty for not complying with obligations should be forfeit of compensation for the month in which they fail to provide market making service.[132] Origin also supported sub contracting, as this may enable more competition and participants. Origin warned against additional costs being passed through to consumers.

The AER considered the operation of a tender and the related compliance and enforcement would impose onerous requirements that are not justified by the incremental benefits of the proposed mechanism above that being developed by the ASX. Origin argued that it is not clear that the AER is the most appropriate body to introduce market making in the NEM.[133]

A.4 Range and specification of products

A.4.1 Proponents view

The proponent considered the tender should specify lot sizes, required cumulative exposure, required spreads and the period of offer for each region that will remain in place for the full duration of the tender period. No specific details or recommendations for these terms were provided in the rule change request.[134]

A.4.2 Stakeholder views

Ergon Energy suggested quarterly caps and swaps should be the included products in a market making arrangement.[135] ERM power suggested a simple suite of products including flat swaps, peak swaps and caps would provide a workable balance to give market participants time to adjust.[136]

Stanwell considered that quarterly swaps and caps would be appropriate. Stanwell maintained that the choice of either swaps or caps or both should be specified in the market making agreement and should be at the discretion of each participant, given not all market making participants will be able to effectively cover the risk associated with some products (caps for example).[137]

Origin suggested that baseload futures should be included and were wary of the inclusion of caps given cap prices historically are more volatile, increasing the risk for the market maker. Origin preferred caps be excluded or have a wider spread permitted.[138]

The AEC suggested standardising products may increase liquidity but at the cost of stifling innovation and hence organically developed market making. The ASX platform may be better than a platform designed by external parties. The AEC suggested the AEMC consider

131 AGL submission p.3.
132 Origin Energy submission p.5.
133 Origin Energy submission p.1.
134 Rule change request p.13.
135 Ergon submission p.4.
136 ERM power submission p.3.
137 Stanwell submission p.5.
138 Origin submission p.4.

whether, after an initial period of limited products to test the market, a future market-making mechanism be introduced which can allow flexibility in the definition of products to allow alternatives to qualify and better meet the needs of participants.[139]

EnergyAustralia considered OTC contracts should be eligible to satisfy market making obligations.[140] Ergon Energy maintained the ASX is preferable for market making given the OTC market has credit constraints for retailers.[141] Stanwell stated that all products should be centrally-cleared to avoid the credit risk of OTC products and that all market making participants should fulfil their obligations on a single exchange in order to concentrate liquidity. The exchange selected for the market making arrangement should be subject to competition.[142]

Ergon Energy indicated that one to two years of quarterly contracts should be adequate. [143] Stanwell suggested that market making commences three years in advance and ceases two quarters in advance. This mechanism would give retailers and customers sufficient time to enter into hedge contracts, while incentivising contracting in advance.[144] Ceasing the obligation two quarters in advance would allow market makers time to finalise their fuel and hedging position after the conclusion of the market making period. In addition, the six months prior to dispatch is already the most liquid part of the forward curve, according to Stanwell, so additional obligations would be expected to provide the least benefit during this period.[145]

Market making trading windows should be the last half hour of the trading day according to both ERM Power and Stanwell. Ergon Energy suggested that a two to four hour trading window should be sufficient.[146] Origin suggested that late morning, around 10:30-11:00am would be a suitable time period. Origin considered that a trading window at the end of the day would be less efficient for the market. Setting the window early provides participants with the ability to hedge and account for positions the same day, increasing the chances of spreading out trading throughout the day.[147]

The maximum bid offer spread according to ERM Power should be the lesser of five per cent and $2/MWh for flat swaps and the lesser of five per cent and $5/MWh for peak swaps, while caps should be 15 per cent. ERM proposed a higher spread for caps due to the fact that these are generally lower priced products and therefore a wider spread is likely to have a lower impact in dollar terms.[148] Stanwell suggested a bid offer spread based on time-frames with three per cent for T-5 to T-1, four per cent for T-1 to T-2 and five per cent for T-2 to T-3.[149]

139 AEC submission p.2.
140 EA submission p.4.
141 Ergon Energy submission p.5.
142 Stanwell submission p.5.
143 Ergon Energy submission p.5.
144 Stanwell p.5.
145 Stanwell submission p.5.
146 Ergon Energy submission p.5.
147 Origin Energy submission p.5.
148 ERM Power p.4.

Origin suggested spreads in the range of five per cent to 10 per cent and pointed to the UK and New Zealand where spreads are five per cent. An inflexible limit, according to Origin, has costs and risk as has been seen in the UK. This is especially the case during periods of high volatility. Origin stated that with information asymmetry, market makers without sufficient spread and having uncertainty about price, are forced to wear more risk, unfairly benefiting speculators. As a result, consideration should be given to allowing a wider spread, for example 10 per cent when prices are highly volatile.[150]

Stanwell stated the minimum contract size should be 1MW for small participants and 5MW for larger participants. ERM Power maintained the commitment to market make should be for a 5MW minimum but with 1MW lot sizes. Ergon Energy considered 1MW should be the minimum size.[151] Origin suggested 1MW to 5MW is ideal but South Australia may require smaller increments. Anything larger than this may make it difficult for marker makers to trade out.[152]

The cumulative risk exposure required for any participant should, according to Stanwell, be a maximum of 10MW per day and only 15MW per week in South Australia due to the small size of the market. Under certain circumstances, such as a trading halt, the release of market sensitive information, or system issues, the obligation should be suspended. Stanwell cited the UK example where under large price movements, market makers had their prices aggressed and then had to pay a premium to reverse those positions.[153] Energy Australia maintained that the AEMC or AER should be empowered to create rules through a consultation process allowing for "breaking glass" events that would require suspension of market making requirements.[154]

Origin suggested that daily limits should be considered, in addition to monthly limits, as this better allows participants to match their portfolio. Monthly volume limits, according to Origin, may be taken early in the month by a few large volume trades, resulting in no market making activity for the rest of the period. In addition, anything that affects a market makers' ability to make prices, for example trading halts, the release of market sensitive information, or unplanned outages, should remove the obligation during the period the information is in effect.[155]

A.5 Jurisdictional specific issues

A.5.1 Proponents view

The proponent recommended that all regions should be included all the time to act as a fail-safe for providers in regions where hedging risk is the most challenging and to alleviate the need for arbitrary triggers to be set and measured.[156]

149 Stanwell submission p.6.
150 Origin Energy submission p.4.
151 Ergon Energy submission p.5.
152 Origin Energy submission p.4.
153 Stanwell submission p.6.
154 EA submission p.5.
155 Origin Energy submission p.5.
156 Rule change request p.12.

A.5.2 Stakeholder views

ERM Power stated in its submission that the current contract market in South Australia warrants intervention to ensure that contracts are available to allow small participants to compete in the market.[157]

On this basis ERM Power said it expected that market making would apply in South Australia immediately. ERM also stated that market making should apply in all regions. Ergon Energy in contrast stated there is currently sufficient liquidity in the Queensland region and therefore there is no need to require a market making arrangement in the state.[158]

Origin maintained that South Australia should be the primary focus, however a voluntary scheme could apply to all regions.[159]

A.6 Commencement date

A.6.1 Proponents view

The proponent expressed no views on a commencement date for market making on the market making proposal put forward in the rule change request.

A.6.2 Stakeholder views

No submissions were made on the commencement date.

157 ERM Power submission p.5.

158 Ergon Energy submission p.5.

159 Origin Energy submission p.5.

B LEGAL REQUIREMENTS UNDER THE NEL

This appendix sets out the relevant legal requirements under the NEL for the AEMC to make this draft rule determination.

B.1 Draft rule determination

In accordance with s.99 of the NEL the Commission has made this draft rule determination in relation to the rule proposed by the proponent.

The Commission has determined not to make a draft rule.

The Commission's reasons for making this draft rule determination are set out in section 7.4.

B.2 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the NEL to make the proposed rule
- the rule change request
- submissions received during first round consultation
- the Commission's analysis as to the ways in which the proposed rule will, or is likely to, contribute to the NEO
- the analysis conducted by NERA on the incremental cost-benefit analysis of different market making options.

There is no relevant Ministerial Council on Energy (MCE) statement of policy principles for this rule change request.

B.3 Application in Northern Territory

From 1 July 2016, the NER, as amended from time to time, apply in the Northern Territory, subject to derogations set out in regulations made under the Northern Territory legislation adopting the NEL (referred to here as the NT Act).[160] The NT Act provides for an expanded definition of the national electricity system in the context of the application of the NEO to rules made in respect of the Northern Territory, as well as providing the Commission with the ability to make a differential rule that varies in its terms between the national electricity system and the Northern Territory's local electricity system.

The Commission has determined not to make a draft rule and, consequently, has not made a differential rule in respect of the Northern Territory.

160 NT Act: National Electricity (Northern Territory) (National Uniform Legislation) Act 2015. Regulations: National Electricity (Northern Territory) (National Uniform Legislation) (Modifications) Regulations.

C MARKET MAKING ARRANGEMENTS IN OTHER ELECTRICITY MARKETS

The Commission has reviewed three international jurisdictions that have market making arrangements for electricity futures and one (Ireland) that examined market making in detail and decided against implementing a scheme.

- New Zealand (voluntary)
- Singapore (voluntary)
- United Kingdom (compulsory)
- Ireland (no market making)

The following sections outline the arrangements and experience in those jurisdictions. Further information on these schemes is available in the NERA report[161].

C.1 New Zealand

Four New Zealand electricity generators voluntarily signed market making contracts with the ASX in 2010. This was a reaction to the government's statement that generators had to achieve "satisfactory market liquidity, defined as 3,000 GWh of unmatched open interest" (contracts without matching offsetting contracts) by 1 June 2011. The Commission understands the four market makers receive a rebate on their ASX fees for providing the market making services.

Unmatched open interest did reach the desired level three years after the scheme's introduction. However, for long periods of 2017 and 2018 the bid-ask price spreads exceeded the agreed five per cent limit, sometimes reaching more than 50 per cent. The conclusion was that the voluntary arrangements have supported strong growth in the volume of fixed-price contracts traded and improved retail competition since 2010, but recent wholesale market conditions have put financial pressure on the market makers, and the Electricity Authority is now examining whether to introduce mandatory or incentivised market-making obligations.

C.2 Singapore

The Energy Market Authority (EMA) introduced an incentivised market making scheme to provide liquidity in the newly established futures market. The futures market and market making scheme began in April 2015. Market makers receive incentives based on transaction volumes. The EMA also provides a performance incentive using a *pool-price* concept that rewards market makers if a minimum overall market volume is met.

The cost of the scheme (i.e the incentive paid to the market makers) is recovered through retail tariffs and has increased contract market liquidity. The futures market transaction volume is five per cent of the annual underlying physical consumption. The scheme is

161 NERA, Costs and benefits of additional market making in the NEM, 24 May 2019

considered successful by most participants, noting that it has been redesigned twice to adjust the level of incentive payments provided.

C.3 United Kingdom

Ofgem, the UK electricity and gas regulator, introduced a mandatory market making obligation in 2014 to improve wholesale market liquidity. The obligation mandated the six largest generators to provide forward products. The mandated parties had to market make for seven base and six peak products four seasons ahead in two hour-long trading windows per day.

Ofgem is currently assessing whether the scheme should remain given its costs and the removal of the obligation on three of the original six market makers due to their divestment of generation assets to below the stated threshold. Increased liquidity in the market making windows was observed as a result of the scheme, but came at the expense of liquidity in the rest of the trading day.

C.4 Island of Ireland

The Integrated Single Electricity Market (I-SEM) began in October 2018 and is the (net pool) wholesale market for Ireland and Northern Ireland (known as the Island of Ireland). The decision-making authority, the Single Electricity Market Committee (SEMC), considered market making as a way of avoiding low liquidity and market power concerns that were observed in the previous SEM forward market.

A Forward Contract Selling Obligation (FCSO) and a Market Making Obligation (MMO) were both considered but ultimately not implemented. A concern was the additional and disproportionate risks imposed on the obligated parties in a new market that was expected to be highly volatile (at least at the beginning). The SEMC stated they will re-assess the liquidity of the I-SEM forward market 18-24 months after the new market commencement date, which includes monitoring the developments of the UK market making obligation.

D ALTERNATE MARKET MAKING MODEL

After the AEMC had engaged NERA to provide a cost-benefit analysis of the alternative market making schemes, the ASX described a variation for consideration. Rather than requiring the market makers to offer to buy and sell contracts, as is required in the compulsory market making scheme, the variation would require market makers to sell a given proportion of their contracts on-market.

The features of this model, compared to the compulsory market making scheme that NERA modelled, are set out in the table below.[162] The obligation would apply to large vertically integrated participants. Key differences between the models are that:

- the obligation is only to sell contracts
- pricing is not specified in the scheme design.

Table D.1: **Features and comparison of models**

FEATURES	COMPULSORY MARKET MAKING	ALTERNATIVE SUPPLY-SIDE MODEL
Products to be offered	Specified	Specified
Contract volumes	To buy and sell contracts (specified quantities)	To sell contracts only (quantities could be specified or a percentage of generation capacity)
Lot sizes	Specified	Specified
Number of trading days and trading periods	Specified	Specified
Price	Buy and sell contracts within a specified bid-ask spread	No price specified

Source: AEMC
Note: Items listed as "Specified"would be dependent on the scheme design, but are assumed to be the same in both models for the purposes of this analysis.

D.1 Preliminary analysis

This section outlines the Commission's preliminary assessment of this model in the following areas:

- liquidity
- pricing
- competitive conduct
- risk.

162 Notably, the scheme design could vary from that described, which could potentially change the identification of issues and conclusions set out in this appendix.

D.1.1 Liquidity

The scheme would improve the supply of contracts compared to not having a market making scheme. Market participants would have confidence that a quantity of contracts would be available to buy. However, the scheme would likely contribute less to liquidity than compulsory (or other) market making schemes because participants would not be able to trade in and out of positions easily. The ability to buy and sell is a key dimension of a liquid market.

Smaller generators looking to sell contracts would not have any guarantee that the market maker would buy any of their contracts, given there is no buy requirement in this model.

D.1.2 Pricing

The price of contracts would not be specified in the scheme design, but the requirement that a generator sell a given proportion of its capacity on-market means a proportion of its internal contracts at transfer prices would be available to, and observable by, other market participants.

This would provide market participants with confidence that a proportion of their contract prices would be equivalent to the vertically integrated participants' contract costs. However, there would be no visibility of the equivalence of other internal trades.

The design of this type of model needs to consider the restrictions that may apply to a firm in relation to it offering and buying its own contracts. Part 7.10 of the Corporations Act 2001 (Commonwealth) prohibits the creation of a false or misleading appearance of active trading in particular financial products on a financial market (Corporations Act 2001 (Commonwealth), s1041B). The prohibition is deemed to include 'wash trades' where there is no change in the beneficial ownership of the relevant financial products (Corporations Act 2001 (Commonwealth), s1041B(2)). Similar prohibitions are included in the ASIC Market Integrity Rules (Futures Markets) 2017.

An exemption from 'wash trades' is potentially achievable, and may allow for a vertically integrated participant to 'cross-the-trade' and buy its own contracts after a set period (e.g. five minutes). The specific design elements around the quantity of contracts made available and time the contracts are available for purchase by third parties, would inform the level of benefit to other market participants.

The relationship between the scheme design and self-trading rules is key. If the scheme requires a participant to trade (not just offer) a given percentage of its generation on-market, and self-trades are not allowed, then the contract prices would have to be adjusted (presumably downwards) until the trading volume requirement was met. Conversely, if the scheme design allows self-trading after a period or in certain circumstances, then the price pressure may be less.

Notably there are additional potential legal issues that would also need to be considered, including potential AFSL implications and relevant limitations to the Commission's rule making powers.

D.1.3 Competitive conduct

As noted, while there would be increased price discovery on a proportion of trades that vertically integrated participants conduct, the broader gaps in market information would not be addressed. In particular, there would be no visibility of the equivalence of other internal trades by the vertically integrated participants. Notably this is also not addressed in the other market making schemes considered, but could be addressed by the increased reporting that is discussed in Chapter 7.

D.1.4 Risk

The scheme would lower the risk to market makers, as it does not expose them to risk on both sides of a transaction. Conversely, other participants would face the higher risks of trading in a market with lower liquidity.

The scheme may increase overall transactions costs, given there would be a higher volume of on-market transactions and these are assumed to cost more than the internal transaction costs of vertically integrated participants.

The market maker also has risk associated with the volume of contracts required in the system design, given it has to meet its internal contracting needs and the requirements of the market making scheme. A vertically integrated participant that was short on generation (overall or in a jurisdiction) may face increased risk if it had to participate in this scheme. However this risk is dependent on the scheme design and is therefore equally present in the compulsory market making scheme.

E COMPARISON OF ASX AND MLO SCHEMES

The AER should monitor the compliance of the market makers in the ASX market making scheme in a way that is consistent with its monitoring of participants' compliance with the MLO if triggered. Understanding compliance with the scheme will be an important input into understanding whether the scheme is delivering sufficient liquidity. The absence of clear compliance data would cloud analysis of whether the scheme design was sufficient and efficient in delivering liquidity. Therefore, compliance monitoring is critical.

Table E.1 shows the key requirements of the ASX market making scheme compared to those of the MLO. The scheme designs converged in the last few months of development and are now closely aligned on most requirements. As the AER is already preparing to monitor compliance with the MLO, it should be relatively simple to extend this compliance coverage to include the ASX scheme, although it is noted that the ASX scheme will run continuously whereas the MLO will only apply in relation to periods where a reliability gap has been forecast.

The Commission understands that market makers in the ASX scheme will receive a monthly compliance report from the ASX on whether they met the terms of the market making agreement. The key terms relate to whether the market maker offered the required product volumes during the required market making periods at the specified bid-ask spreads. If the market makers comply then they are eligible to receive the scheme incentive payments, including exchange fee rebates and a share of profit associated with the growth in trading that the market making scheme delivers.

The AER will not have automatic access to the ASX compliance report for market makers, nor does it have powers to compel the ASX to provide specified data. The AER will therefore have to require compliance data directly from participants, or come to an alternative arrangement with participants and the ASX.

Table E.1: **Comparison of market making scheme key terms**

INDICATOR	ASX MARKET MAKING	MARKET LIQUIDITY OBLIGATION
Obligated parties	Corporations agreeing to ASX's market making contract	Generators with 15%+ of scheduled generation in a region.
Number of market makers per region	At least 2 obligated parties in each region.[2]	
Lot size	1MW	
Minimum volume to be traded per trading period.[3]	5MW (QLD, NSW & VIC), 2MW (SA).	
Products	Base futures (quarterly), Cap futures (NSW and VIC only) (quarterly).	Base and peak futures (monthly, quarterly), cap futures (quarterly) and any others approved by AER.
Spread - base load futures	5% or $1/MWh, whichever is higher (QLD, NSW & VIC), 7% or $1/MWh, whichever is higher (SA).	
Spread - cap load futures	10% or $2/MWh, whichever is higher	10% or $1/MWh, whichever is higher
Period of operation	• Commencement: 1 July 2019. • Duration: ongoing. • Tradable period: quarters 2-8.	• Commencement: 5 days from issue of T-3 Reliability Instrument (RI) by AER. Under the SA derogation, the SA Minister can issue a T-3 RI. • Duration: Five days from the issue of T-3 RI until issuing of T-1 RI, or AER determines MLO not needed. • Tradable period: period when liquidity obligation is in effect.
Trading platform	ASX24	AER approved trading facility. RRO transition roles consider ASX24 as an approved facility.
Incentives	Exchange trade fee rebate (fixed & growth based), revenue share payment.[4]	None – compulsory scheme.
Periods when parties must market make	25 minutes in each session, except for up to 10 market making sessions at the discretion of the obligated party.[5]	

INDICATOR	ASX MARKET MAKING	MARKET LIQUIDITY OBLIGATION
Conditions where market making obligations cease	• Lack of availability or disruption of the performance of the Trading platform. • Entering into a contract will cause a participant to break the law.	• Once net sales limits are reached (for period & region). Daily: 5MWs sessions (except SA – 2MWs); Quarterly: 1.25% of the MLO group's generation capacity, Total: 10% of the MLO group's generation capacity. • Trading halts on exchange or prohibition imposed on participant. • Participants can decide not to participate in 10 trading periods of their exchange per month. • When trading constitutes a breach of s588G or 588V (Corporations Act). • Any other circumstances set out in AER Guidelines.

Source: National Electricity Amendment (Retailer Reliability Obligation) Rule 2019; ASX information.

Note: [1] Content on these tables depicts key elements of both market making schemes in summarised format for the purposes of comparison between the two initiatives, please refer to MLO rules and to the ASX for detailed scheme information. [2] Under the MLO there must be at least two "MLO groups". [3] For each Product, the Minimum Quantity of Contracts for each Calendar Quarter in a Market Making Session will be reduced by the number of Contracts in that Calendar Quarter (if any) traded by the MM in that Market Making Session. [4] Formulas to calculate incentives are confidential in nature. [5] Market making session: periods between 11:00am–11:30am and 3:30pm-4:00pm on a business day (both schemes), parties must market make for those two sessions in each day. In general terms, under the MLO an MLO generator performs its obligation if offers are available for at least 25 minutes in each session.

F CONTRACTING FOR GAS TO MEET THE MLO AND ASX MARKET MAKING REQUIREMENTS IN SOUTH AUSTRALIA

The MLO requires specific generators to make contracts available for retailers to buy in order to fulfil the RRO. In South Australia, the Minister has additional discretion to trigger the MLO, and it may therefore come into effect earlier and more regularly than in other States.

The ASX market making scheme will also require generators to make additional contracts available in South Australia.

Gas powered generation is the dominant form of firm generation in South Australia, and so the availability and price of gas and gas transport is a key determinant of whether contracts can be made available and at what price.

Gas trading in South Australia occurs under the contract carriage model. Generators must have gas transportation agreements with the pipeline operator in place to transport gas. The terms for access are negotiated and can be firm or non firm (interruptible). Market makers require firm access to capacity in order to offer firm contracts.

Gas supply and transport are typically contracted long term. Gas transport provides for the delivery of a maximum daily quantity (MDQ) between two points on a pipeline. Gas supply agreements have provisions for an annual quantity of gas to be delivered, and also a maximum daily quantity. Long term agreements are bilaterally negotiated off market and there is little publicly available information on the terms of these agreements.

Gas supply can be purchased shorter term through the short term traded markets (STTMs). The STTM is a voluntary day ahead gas balancing market with hubs at Sydney, Adelaide and Brisbane. A market clearing engine uses bids, offers, and forecasts submitted by participants, along with physical constraints to determine gas schedules. To participate in the STTM, participants must hold rights to transport gas along the relevant pipeline(s). There is no forward price certainty for gas bought through the STTM, and so this is unlikely to help market makers offer capacity in the future at a pre-determined cost.

Gas transport capacity can also be purchased on a short-term basis. The ACCC noted in their recent 2018 Gas Inquiry Interim report that an increasing portion of new GTAs have terms of one year or less. Capacity can be purchased either directly from the pipeline owner ("primary trade") or from the holder of current capacity rights ("secondary trade"). AEMO publishes an uncontracted capacity outlook for each pipeline on the gas bulletin board, providing gas buyers and shippers with information on spare pipeline capacity up to 12 months ahead. One of the ACCC and GMRG joint recommendations in their December 2018 report on *measures to improve the transparency of the gas market* is to require AEMO to extend the outlook to 36 months. Secondary trade agreements for gas transport, are often on an 'as available' or 'interruptible' basis which have a lower scheduling priority to a firm service and therefore may not be appropriate for market makers looking to offer firm contracts.

Even though short term capacity may not always be firm, short term trading of gas supply and transport capacity can be used to manage longer term contracts and allow market makers to optimise or adapt their position by buying or selling capacity at the margin.

Trading of short term capacity has become easier through the capacity trading reforms introduced in the gas market in March 2019. Some pipelines had been fully contracted with little or no secondary capacity trading. Two components of the reforms, the Day-ahead Auction (DAA) of contracted but un-nominated capacity and the AEMO operated Capacity Trading Platform (CTP) may help to facilitate greater access to capacity and greater visibility over price and other key terms. The reforms provide pipelines with an incentive to trade spare capacity on the Capacity Trading Platform (CTP). Any contracted but un-nominated capacity that is not traded before the cut-off time is offered to other participants through the Day-ahead Auction (DAA).

While the day ahead auction may not be suitable for market makers, given the capacity auctioned is both non firm and only available for the day ahead, it may increase short term capacity offered on the capacity trading platform in the future given owners of pipeline capacity do not derive a benefit from day ahead auction revenues, but would receive revenue from capacity offered on the capacity trading platform.

There are other short term options available to generators looking to meet market making commitments, but they are expensive. Linepack, gas that is stored in pipelines, can be purchased at short notice, but generally a premium is paid to gain access to this gas. Alternatively, some gas generators can use alternative fuels during periods where gas is unavailable or prohibitively expensive. There are also short-term forward products available on the Gas Supply Hubs (including at Moomba) however the fixed cost nature of these products are not well suited to the variable nature of peaking generation demand.

While the situation is likely to improve given the capacity trading reforms recently enacted, contracting for gas to meet market making commitments in South Australia is likely to remain challenging and expensive, particularly for peaking gas generators looking to meet market making commitments. The firmer the gas supply required and the greater the variability of gas load, the higher the overall cost of delivered gas.

Even when gas and transport is available to meet the requirements of peaking generators, the economics of providing firm hedges through gas generation are likely to result in high priced contracts that may attract limited demand.